TIDAL POWER STUDY
COBSCOOK BAY, MAINE

PRELIMINARY REPORT ON THE ECONOMIC ANALYSIS OF THE PROJECT

MARCH 1979

UPDATED JULY 1979

United States Army
Corps of Engineers
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New England Division

TIDAL POWER STUDY

IN

COBSCOOK BAY, MAINE

"Preliminary Report on the

Economic Analysis of the Project"

March 1979

Updated July 1979

Prepared by: U. S. Army Corps of Engineers
New England Division
Waltham, Mass. 02154

FOREWORD

The natural, high tidal phenomenon in the Cobscook Bay Region of the State of Maine is the best in the contiguous United States for the purpose of developing hydroelectric power.

Numerous engineering studies have been performed for harnessing the tides. However, historically, over the past fifty years of studying the utilization of the high tides in the area for generating electricity, the economic feasibility of tidal projects has been marginal, at best. In view of this, it was recommended that periodic economic re-analysis of the project be accomplished as the current study progressed. This was to determine at various intervals if further investigations and study of the project was warranted.

This special economic study for the Cobscook Bay Tidal Power Study is based on a more refined methodology called relative price shift analysis; and was performed as a result of review and recommendations by Office of the Chief of Engineers on a previous project economic analysis based on "life-cycle costing methods" accomplished by the New England Division in April 1977.

It is noted that project economic justification is still based on the "net benefit rule," and that other economic methods, such as life-cycle and relative price shift analysis, are not authorized at this time. However, in view of the region's energy problems and the potential that tidal power offers, it has been determined to analyze the project under various projected economic scenarios.

IMPORTANT NOTICE to readers of this report:

This document contains an economic analysis of tidal power potential in Cobscook Bay, Maine.

Initially, relative price shift analysis was conducted in January of 1979 for this report. While the report was being reviewed by our Washington Office, oil prices were changed rather dramatically. Therefore, a new relative price shift analysis was undertaken in July 1979, using July price levels. The results of the July analysis are shown on page ii and iii of the executive summary of this report.

Environmental concerns, marketing, detailed cost estimates and other data are to be addressed in a reconnaissance report that will be completed and released at a later date. The forthcoming report containing the Division Engineer's recommendations will be submitted to Congress.

Questions pertaining to this preliminary economic report should be directed to:

Division Engineer
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Waltham, Massachusetts 02154

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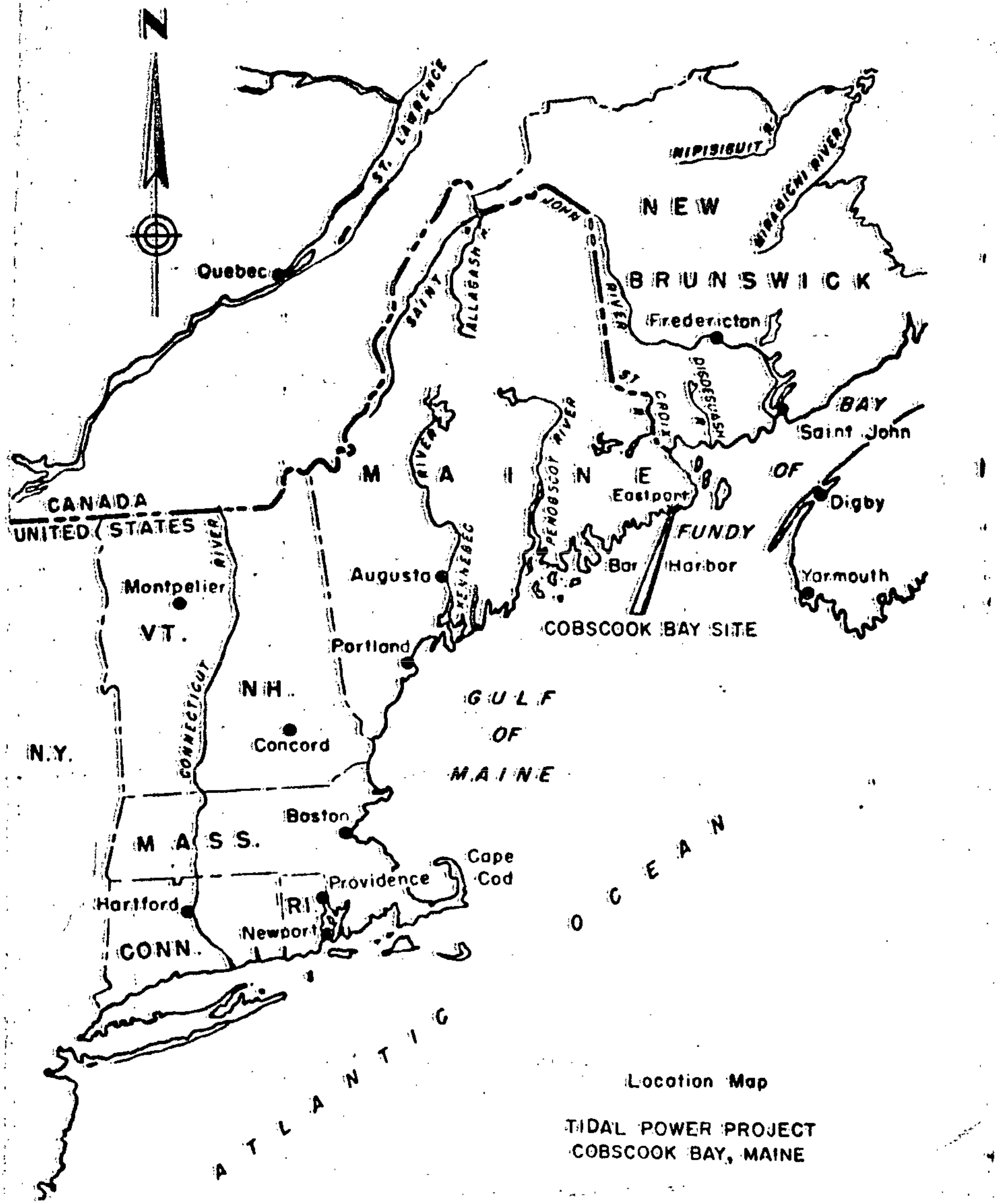


Location Map

TIDAL POWER PROJECT
COBSCOOK BAY, MAINE


N
COBSCOOK BAY
MAINE
PEMBROKE

Executive Summary

General

The subject of economic feasibility of Tidal Power Projects in the Passamaquoddy-Cobscook Bay Region, of Maine, has been addressed in several previously published reports. Historically, due to the high initial capital outlay, the lack of dependable capacity, and the low price of fossil fuels, Tidal Power Projects in the region have always been economically unattractive. In the past, maximum conventional benefit-to-cost ratios computed for power only, have never exceeded 60% and were more frequently around 35%. However, an initial analysis of a representative tidal project using a life-cycle methodology, based upon total cost escalation, after project construction including inflation, led to positive net benefits. One of the major purposes of this interim economic study is the application of a refinement of the above life-cycle methodology. This methodology revision, to focus upon relative price shifts (net of general inflation) among various commodities employed in the generation of power either by the tidal power project or the alternative to the project, was necessary in order that the analysis be in accordance with the Water Resource Council's Principles and Standards.

In accomplishing the economic update of the tidal power potential in Cobscook Bay, numerous tidal power alternative layouts were investigated with installed capacities varying between 5 to 450 megawatts. The types of generator and turbine equipment were re-considered and new preliminary construction, operation and maintenance costs were prepared. Updated annual benefits were derived for power only, and annual costs were determined and included in the analysis. Ancillary benefits which are possible from area redevelopment, recreation and fisheries - mariculture, were not included. Environmental concerns were not assessed or evaluated at this time.

The primary purpose of this current economic analysis is to re-analyze the economic feasibility of a tidal power project in the region and to determine if further investigation and study is warranted.

Approximately 90 Tidal Power Alternatives have been considered in this study. These were all contained in Cobscook Bay, Maine, and included single pool, multi-pool, and linked basin configurations. The alternatives included various impoundment areas and different sizes of generating plants.

As a result of this recent investigation, the following general observations appear to be applicable:

- Since the alternative for linked or multi-pool tidal power configurations is nuclear power, and since an installed capacity that is approximately 3-4 times the dependable capacity is required due to the nature of the tides, it appears that shemes designed for dependable capacity are too expensive and Tidal Power Projects should be designed to maximize energy (plant factor) rather than dependable capacity.

- Single pool alternatives with large impounded bay and relatively small installed-capacity generating plants yield the greatest economic (energy) advantage.

- No capacity credit was taken for single pool plans.

- Since the Federal Energy Regulatory Commission's (FERC) cut-off between combined cycle (31 mils/kwhr) and nuclear power (7mils/kwhr) as alternative type power plants occurs at a 40% capacity factor, tidal power plants are not economical at a greater than 40% capacity factor.

Selected Project Analysis Summary

The table below shows the conventional benefit-to-cost ratios for the five most economically favorable tidal power alternatives. These single pool projects represent optimal projects based on January 1979 FERC policy. A federal interest rate of 6 7/8% was used for this analysis.

BENEFIT-TO-COST RATIOS FOR SELECTED PROJECTS

Dam (Capacity Factor)		Installed Capacity (MW)	Annual Energy (GWHR)	Annual Cost Tidal Power Project $1000	Annual Cost Transmission Lines $1000	Annual Benefits $1000	BCR * Jan	BCR * Jul	Engy Cost mils/kwhr
Dudley	.39	160	553	34,245	3,064	17,006	.46	.55	68.0
Cooper	.39	140	490	27,889	2,765	15,068	.49	.59	63.1
Cable	.40	135	475	27,281	2,706	14,592	.49	.59	63.7
Goose	.40	135	468	26,676	2,636	14,377	.49	.59	63.2
Birch	.38	110	388	22,198	2,271	11,920	.49	.59	63.6

NOTE: Transmission costs included are estimated from data in December 1978 DOE letter report. Losses of energy during transmission are taken as .009 in benefit calculations.

Relative price shift methodology was utilized in the analysis of the projects listed in the above chart. Relative price shift analysis goes beyond a static benefit-to-cost comparison by considering changes in underlying price relationships that might occur over the life of the project. Real price changes, net of general inflation, are used in this methodology.

* Price of oil used:
January 1979 - $16.50 per barrel
July 1979 - $24.00 per barrel

The analysis focused upon the impact of shifts in the relative price of oil, the fuel input to the most likely alternative's generation process, upon the benefit-to-cost ratios of the various projects.

Three different levels of annual oil price escalation were utilized and these are detailed in the following table:

	1978-1994	1994-2023
Low Rate	1%	1%
Medium Rate	3%	1%
High Rate	5%	1%

The initial rate was used to update 1978 energy input values to 1994, the assumed first year of project operation. The second rate was used to escalate energy input values during the first thirty years of project operation. Based upon these scenarios, the following benefit-to-cost ratios were developed:

Project	January 1979* Price Levels 1%	3%	5%	July 1979* Price Levels 1%	3%	5%
160 Dudley	.52	.67	.87	.69	.89	1.17
140 Cooper	.56	.73	.94	.74	.96	1.26
135 Cable	.56	.72	.93	.73	.96	1.25
135 Goose	.56	.72	.94	.74	.96	1.26
110 Birch	.56	.72	.93	.73	.96	1.25

A second statistic of relevance in relative price shift analysis is the break-even year. This is the year after project construction completion in which the escalating power value equals or exceeds the cost of power generation from the tidal alternative. After this point, the project begins to pay for itself.

Break-Even Point (in years)

Project	Break-Even Value (mills/kwh)	Fuel Escalation Rates 1%	3%	5%
160 Dudley	68.0	-	-	26
135 Cable	63.7	-	-	19
140 Cable	63.1	-	-	18
110 Birch	63.6	-	-	19
135 Goose	63.2	-	-	18

These tables indicate that while at the high fuel escalation rate the project's power cost will be lower than the alternative's at some point in the future; over the 100 year period beginning in 1994, the initial higher cost of the project's power is not compensated for by future, more heavily discounted, savings.

It should be noted that while all engineering analysis used for this study is preliminary in nature, the results are considered to be adequate for economic screening purposes.

Summary of Findings and Conclusions:

From an engineering and construction point of view, the tidal power project remains feasible; however, the summary of the project from an economic evaluation at this time is as follows:

The utilization of relative price shift analysis brings out the economic energy benefit associated with tidal power much more clearly. This dynamic economic approach results in the various tidal power project's benefit-to-cost ratios being enhanced. However, with this methodology and assuming relative price shifts for oil along expected levels, tidal power, while eventually providing net benefits during several years in the high escalation rate case, does not provide net benefits over the life of the project. The reasons for this include those which have always weighed against the tidal power concept - i.e. high initial cost and lack of dependable capacity; and the more recent infusion of funds into alternative, and in many cases, less expensive forms of energy. Thus, tidal power, though more competitive today, is still not justified, utilizing the assumptions made herein, on the basis of economic analysis as applied in accordance with the Water Resource Council's Principles and Standards.

Although the project does not meet the "net benefit rule" utilizing the conventional benefit-cost ratio method, it appears that a tidal power project may have merit when some of the current events effecting energy are better known and full evaluated. Therefore, a few alternate future possibilities for the five better tidal projects are noted as follows which indicates there is some appropriateness to permit the study to continue.

1. If the total estimated annual ancilliary benefits ($7,000,000) from the project for fisheries-mariculture, recreational and area redevelopment are added to the power benefits, the conventional benefit ratio would increase for the five (5) better tidal projects, from a range of .46-.49 to .64-.77.

2. If the same projects are evaluated on relative price shift analysis and include the $7,000,000 ancilliary benefits, the BCR increases to:

"Real" Fuel Escalation Rates (Percent per year)

BCR	1978-1994	1994-2023
.71-.85	1	1
.86-1.0	3	1
1.05-1.22	5	1

3. Private alternative projects are allowed approximately $195/kw for dependable capacity. Tidal projects have reliable and predictable capacity although it is not dependable in the hydroelectric sense. If the tidal projects were allowed capacity credits in addition to relative price shift analysis, the capacity value credits required to bring the BCR up to unity are as follows:

"Real" Fuel Escalation Rates (Percent per year)

Required Capacity Credit	1978-1994	1994-2023
$96-112/kw	1	1
$59-77/kw	3	1
$13-30/kw	5	1

NOTE: Ancilliary Benefits are not included

4. If the ancilliary benefits and relative price shift is included, the capacity credits required to have a BCR equal to unity are as follows:

"Real" Fuel Escalation Rates (Percent per year)

Required Capacity Credit	1978-1994	1994-2023
$30-60/kw	1	1
$ 0-33/kw	3	1
$ 0	5	1

5. Currently the Federal Energy Regulatory Commission considers nuclear power, with 7 mils/kwhr for energy value, as the alternative to any tidal plant having a Capacity Factor greater than 40%. If the FERC would consider allowing a 50% Capacity Factor as a breaking point instead of 40%, the tidal power projects could then be evaluated on using the rate of 31 mils/kwhr. This would increase the conventional BCR range for selected projects from .46 - .49 up to .51 - .56 and further enhance the base economic conditions and subsequent BCR evaluations by about 10%.

6. The table below shows the results for relative price shift analysis as described on page iii for projects having capacity factors greater than 40%. This analysis assumes that FERC relaxes its criteria as discussed in the previous paragraph and allows a power value of about 31 mil/kwh. No ancilliary benefits are included.

		1%	3%	5%
120	Dudley	.55	.71	.91
110	Cooper	.58	.75	.97
100	Cable	.60	.76	1.00
100	Goose	.60	.78	1.01
85	Birch	.58	.75	.97

Based on the above six alternate possibilities, it appears within reason that the study should not be discontinued at this time. Further, that meetings between personnel of the Federal Energy Regulatory Commission, the Office, Chief of Engineers, and the New England Division be held to discuss these findings, the economics of the project, and the capacity credit and capacity factor issues. With these meetings, it is considered that a decision on whether to continue or terminate the study can be made by mid-Summer of 1979.

I. Introduction

The Economic Analysis was accomplished between October 1978 and February 1979, and provides latest information on the tidal power alternatives and their economic analysis.

A. The Scope of the Economic Analysis Study

This economic analysis is based on evaluating preliminary engineering concepts and costs of tidal power alternatives. For various structures of the tidal power project, considerable in-depth investigations were made during prior studies and remain usable.

Some of the tidal power concepts reviewed and analyzed are those utilized in the 1935 - 1936 period, and other configurations were formulated recently.

The economic effort was accomplished in the early stages of planning, known as Stage II - Development of Alternative Plans.

B. Organization of the Report

The report contains an Executive Summary, five (5) Sections, and three (3) Appendices.

The Executive Summary provides a synopsis of the project economic analysis at this stage of study.

Section I - Introduction presents the scope of the economic analysis, the study participants and tasks, design changes affecting the analysis, past tidal power studies, and why tidal power has been re-studied.

Section II - Tidal Power Alternatives provides sketch maps of the various alternatives considered and reflects the different dam configurations. Pertinent data in table form is presented for the alternatives with respect to installed capacity and annual energy produced, etc.

Section III - 1979 Project Cost Estimates describes the cost methodology, assumptions, and criteria utilized. The Cost Estimating Computer Program, which was developed for costing on the Alternatives is discussed as well as a few sample project estimates. Some general observations are made on different types of projects as a result of the study.

Section IV - Relative Price Shift Analysis discusses the economic feasibility of the project, using preliminary method in 1977, and the current relative price shift analysis which considers changes in underlying (real) price relationships that might occur over the life of the project.

Bibliography - Lists various reports pertaining to tidal power in the Passamaquoddy and Cobscook Bay areas.

Appendix I - Contains copies of Letters and Reports from Other Agencies, Consultants and Corps of Engineers New England Division.

Appendix II - Cost Estimation contains information on how project costs were derived, typical cross-sections on the dams, and cost estimates for each of the tidal power alternatives studied.

C. Study Participants and Tasks

The economic analysis involved the input of numerous engineering and economic activities. Briefly, a summary of major tasks and organizations accomplishing them are as follows:

Federal Energy Regulatory Commission - Furnishing power values and other information for economic analysis of selected typical tidal power projects.

Bonneville Power Administration - Providing preliminary estimated construction, operation and maintenance costs for electrical transmission facilities to carry the power to nearest feasible points of connection to the New England electric distribution grids system.

Stone & Webster Engineering Corporation - Provide a preliminary review and make recommendations as to the size and type of turbine and generating equipment to be utilized for the project. Also, to prepare preliminary cost estimates for the equipment and powerhouse.

Perini Corporation (Marine Division) - Furnished general overview comments on proposed construction methods for average typical tidal power configurations.

Meta Systems, Inc. - Furnished information and data on relative price shifts among certain commodities.

Corps of Engineers, New England Division

Engineering Division

- Provided preliminary hydrology, capacity, and annual generation quantities, information and evaluation.
- Prepared preliminary cost and quantity estimates for the various project configurations.

Planning Division

- Accomplished economic analysis of the project.
- Provided study management and coordination activities and report preparation.

D. Changes Affecting the Analysis

During the course of the analysis, various reviews, reconsiderations, and changes in the project were accomplished. The most significant changes are as follows:

a. It was recommended that Bulb-type of turbine and generator units be utilized in lieu of the Slant-type units previously utilized in the 1963 and 1977 reports. The use of the bulb units require a smaller civil-type structure to house them, and additional savings in the project can be realized.

b. The depth of dams required in the Cobscook Bay concepts are not as great as those required in the previous international plans. Based on this and on discussions with a marine contractor, it was determined that the slope of dams could be 1:2, which somewhat reduced the fill material required.

c. The larger size vessels do not traverse Cobscook Bay as they do in Western Passage, Head Harbor Passage, and Passamaquoddy Bay. In view of this, many of the alternative configurations in Cobscook Bay include the smaller navigational lock (95' X 25' X 12' deep), which will adequately care for local fishing and recreational boats. The alternatives utilizing dams at Dudley Island locations include the larger locks (415' X 60' X 21' deep). The larger navigational locks (up to 1250' length), which might be required for a proposed oil refinery with Marine Terminal in Cobscook Bay, was not included in the analysis.

d. The economic analysis includes revised capacity and energy values for the project which were provided by the Federal Energy Regulatory Commission. For the single pool concepts where the power is not dependable, no credit was allowed for capacity, and in most cases, the energy value is taken as 31 mils per kwhr. For linked or two-pool project, the capacity value is 195.00/kw and 7 mils/kwhr.

In the previous 1977 study, the energy value used was only 24 mils per kilowatt hour, and a capacity benefit of $25.00 per kilowatt was allowed for the dependable power produced by the two pool concepts.

e. A greater range of alternative size tidal plants were considered, ranging between 5 and 450 megawatts of capacity and producing annual energy between 16 - 790 gigawatt hours. Prior Cobscook Bay studies were based on projects 40 - 250 megawatts of capacity and 292 - 615 gigawatt hours of electricity. The increase in the number of plants evaluated afforded an opportunity to determine the optimum facilities based on purely economic criteria.

f. This analysis had the benefit of the results of a preliminary report on Transmission Lines for the tidal project recently completed by the Bonneville Power Administration. Transmission Line costs, and those of associated structures, while not included in the previous analysis, have been included in this refinement.

E. The 1979 Preliminary Economic Analysis

Ordinarily, an economic analysis of this nature would not be prepared until further on in the study period when more detailed engineering efforts were completed. Such a study would address specific items including more detailed information on bay bottom composition, approximate foundation requirements for dams, preliminary sections showing typical powerhouses, fishways, gates, locks, dams, detailed preliminary layouts for each alternative, numbers of turbines, and similar survey study-level type data. The current study contains cost estimates based on several preliminary concepts applied universally to all alternatives. However, some of the concepts possess excellent preliminary information, and are considered reliable, and offer a good measuring point for similar plans.

The reason this study was undertaken without complete preliminary engineering information was the marginal economics of previously studied tidal power projects. It was felt that an economic study at the outset and at various checkpoint intervals of the survey-level study would assist decision makers in determining the course of the survey study as it progressed.

Since this is an economic study, no environmental data is presented. The survey-level study, if carried to completion, will, of course, address environmental and other aspects in detail.

The major effort in this study has been economic and the analysis is preliminary in nature. The price projections used for the relative price shift are based on the best available information on future trends.

It is believed that all the preliminary economic and engineering analysis done for this report has a good basis and is indicative of the results one would expect after completion of a three year survey-level study.

F. Past Economic Studies on Tidal Power in the Passamaquoddy Bay Region

Since 1920 when Mr. Dexter P. Cooper first analyzed the potential of tidal power, the Passamaquoddy-Cobscook area has been studied extensively. In 1935 the Corps of Engineers actually started construction of a tidal power project in Cobscook Bay during President Roosevelt's tenure. From 1948 to 1961, engineering and economic feasibility of a tidal power project in the Passamaquoddy Bay area was studied and reviewed by an International Engineering Board. From 1963 - 1965, the U. S. Department of the Interior, in conjunction with the Corps of Engineers, reviewed and refined prior studies. Also, since 1973 the New England Division, Corps of Engineers, has intermittently reviewed the economic and engineering feasibility of various tidal power projects in the region.

If the Cobscook Bay Tidal Power Project had been built in 1936, the estimated annual cost over its 100 year life would have been 2.4 million dollars. The cost of energy from a plant estimated to produce 308,000,000 kwhr annually would have been 7.8 mils/kwhr. This is quite low when compared to today's production costs.

As recently as 29 April 1977, the Corps, using the traditional form of economic (benefit/cost ratio) analysis, reported that the cost of building and operating a large, tidal installation in this region would exceed the benefits. The same conclusion was reached in a separate report compiled by the Department of Energy (formerly the Energy Research and Development Administration - ERDA) in early 1977. This was based on the benefit/cost ratio which results from comparing a project's estimated annual power benefits; i.e., the cost of producing needed power by an alternative means, with total annual project costs; i.e., operation, maintenance, major equipment replacements and initial investment converted to annual costs. For a project to be justified economically, the annual benefits would have to be either equal to or greater than the annual costs. Since this is a power project, its justification should be based on power benefits alone. Currently, BCR's for the 1935 alternative based on 1 January 1979 price levels are estimated to be about .35 to 1.00.

Due to the energy situation and rising cost of fossil fuel generating alternatives, former Governor Longley of Maine suggested the feasibility of tidal power be re-evaluated based on "life cycle" costing.

In response to the Governor's request, dated September 7, 1976, the Corps performed a preliminary life cycle cost analysis on the International Passamaquoddy Tidal Power Project. Separately and concurrently, a preliminary life cycle cost analysis was also prepared by ERDA for one of the Cobscook Bay alternative projects. The two independent studies arrived at similar conclusions, which indicates the projects were economically feasible when viewed from this method of analysis.

Two significant factors require that the project's economics be re-analyzed:

- To the extent that the initial life cycle cost analysis included general inflation in the escalation rates utilized, it was not in accordance with the Water Resource Council's Principles and Standards.

- The need to incorporate refinements in cost data listed above in section I. D., entitled: "Changes Affecting the Analysis."

G. Why Tidal Power has been Repeatedly Re-studied

Every time tidal power has been studied, it has been found to be economically unjustifiable using the standard "static" benefit-to-cost ratio methodology. Yet the fact remains that if the original tidal power project had been built in 1935, it would be producing energy at a cost of less than 1¢/kwhr. This, compared with the fact that since 1935 several cost-cutting technical improvements have been made in turbine design, causes some speculation that performing a dynamic economic analysis might be appropriate. The 1976 life cycle analysis represents a first step in the development of a method of dynamic economic analysis for a specific project. The 1979 relative price shift analysis represents a refinement of this methodology.

Of course, as a clean renewable source of power, tidal power appears to be very attractive. Power would be available predictably and reliably twice a day with minimal impact on land and air resources. No fuel would be required. No new areas would be inundated. Aquatic habitat would be affected and power would be available only at proper tide conditions based on the lunar cycle (sometimes at 6 P.M. and other times at 2 A.M. Water circulation in the bay and its estuaries would be affected. Oil, or other fuels, however, would be conserved. Area recreation, fisheries, and transportation probably would be enhanced. Tidal power has been demonstrated successfully in France and the Soviet Union.

While the disadvantages associated with a tidal plant - large initial capital outlay and lack of significant dependable capacity - are still manifested in tidal power not being economically justified in a benefit-to-cost basis, the attraction of utilizing the daily tides to get "something for nothing"; i.e., utilizing renewable resources, remains strong.

By Senate Resolution dated 21 March 1975 and sponsored by Senator Edmund S. Muskie, the Corps was requested to investigate the feasibility of tidal power in the Cobscook-Passamaquoddy Bay Region under present conditions. In late 1976 the New England Division found that the BCR's for the international tidal plans were still less than unity. However, based on a request by Governor James B. Longley of Maine in September 1976 the New England Division investigated the projects under "life-cycle" costing methods. The procedure utilized general inflation and the project appeared feasible and would commence to pay for itself approximately 20 years after commencement of plant operation if the annual inflation rate was 5% and the interest rate was 6 3/8%. By 1st Indorsement dated 27 September 1977 the Office Chief of Engineers advised NED not to use general inflation in the analysis but to proceed with caution utilizing "relative price" shift methods. This report is the first economic effort completed under this method for the tidal power project and is described in Section IV herein.

II. Tidal Power Alternatives

Thirteen (13) tidal power dam configurations have been considered for this preliminary estimate. Figures II-1 to II-12 show the location of and pertinent data for each dam configuration. For most dam configurations, four (4) different levels of capacity and energy have been analyzed, with a total of approximately 90 tidal power alternatives evaluated. The method of analysis is presented in Appendix II.

Each of the sketch maps showing the Tidal Power Alternative contains pertinent data on the project. The following footnotes apply to the sketches:

1. These BCR's do not include transmission costs. A reduction of .03 to .05 would result if transmission costs were added.

2. Efficiency of the thermal alternative was assumed to be 40%.

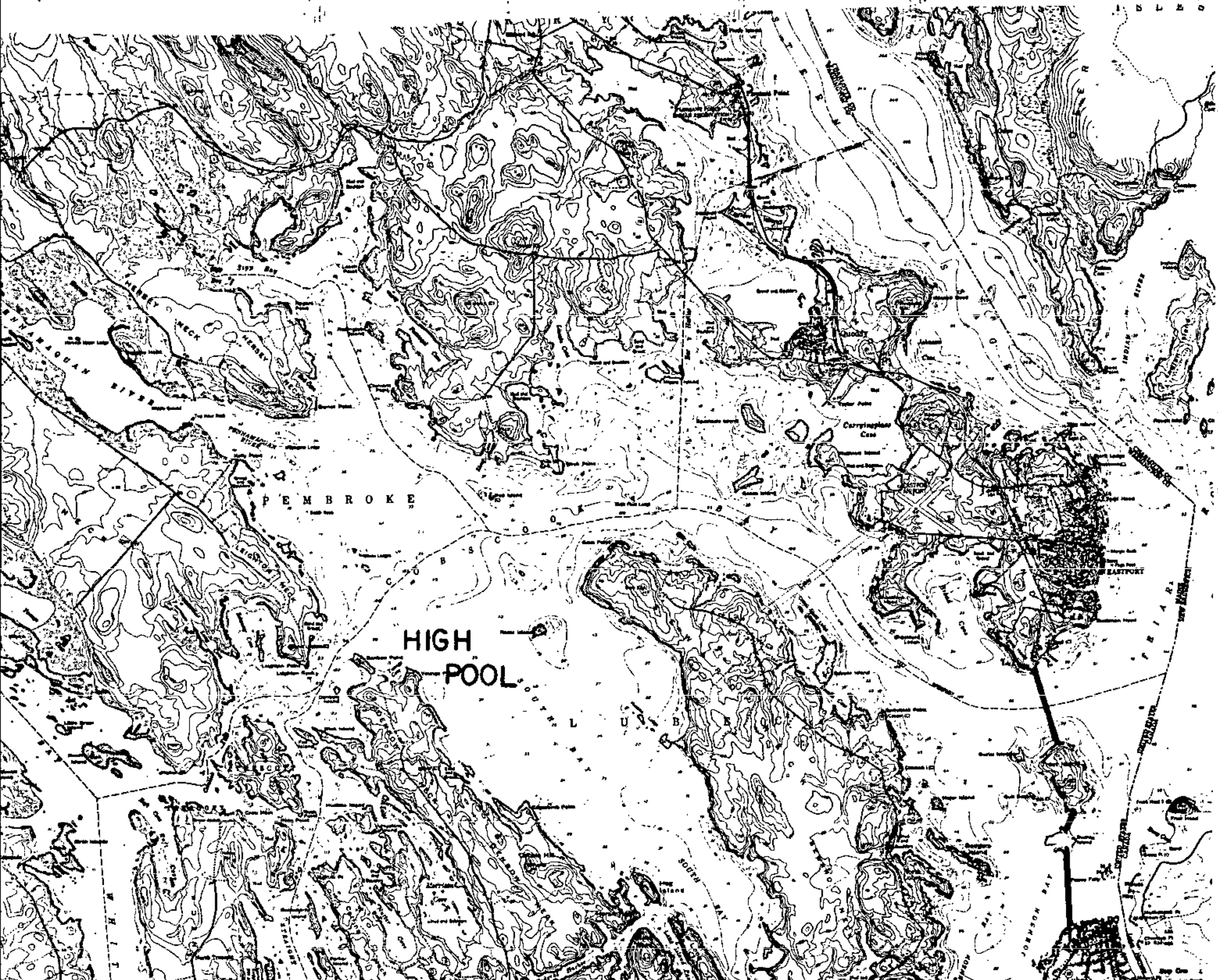
3. A cost of $16.00/barrel was used.

4. 1 January 1979 Price Levels.

5. Figures in parentheses (7) indicate dependable capacity in MW in two-pool and linked basin alternatives.

Figure II-13 provides summary data on the alternative projects and includes information on capacity factor, installed capacity, annual electrical generation, area of the impounded bays, and the number and size of the filling gates required.

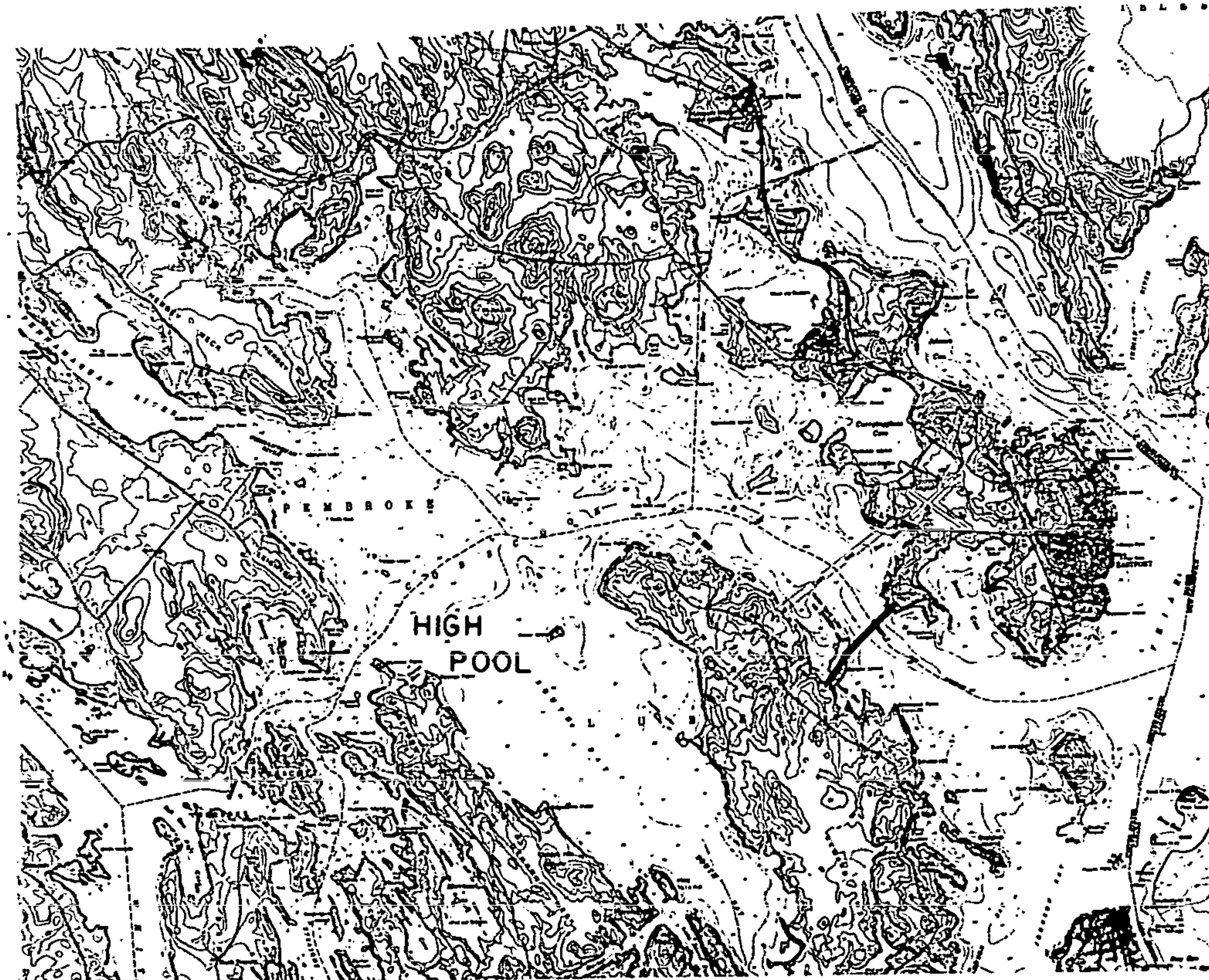
Information for this study regarding hydraulics and hydroelectric aspects of this report can be found in three (3) Corps' memos and in a letter report by Stone & Webster contained in Appendix I.



DUDLEY

Capacity Factor	48	39	30	20
Installed Capacity (MW)	120	160	230	450
Annual Energy (MWHR)	500,000	553,000	605,000	790,000
Conventional BCR	.12	.50	.43	.33
Barrels of Oil Equivalent	705,500	780,283	853,655	1,114,690
Cost of Oil Equivalent	$11,288,000	$12,484,528	$13,658,480	$17,835,040
Energy Production Cost mils/kwhr	56	62	74	96
Annual Cost of Tidal Plant	$28,136,944	$34,245,386	$44,683,826	$76,133,211

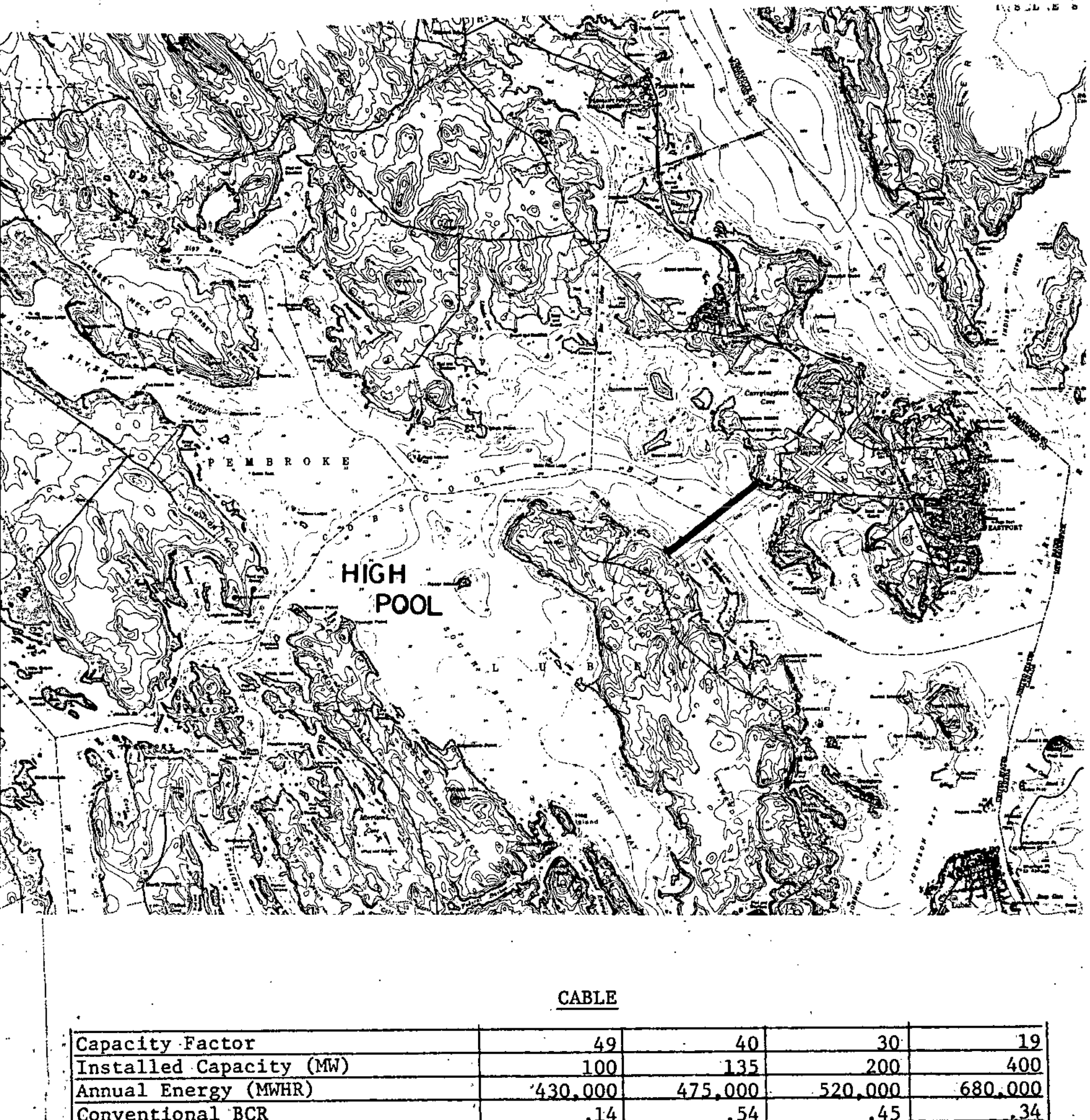
FIGURE II-1



COOPER

Capacity Factor	46	39	31	19
Installed Capacity (MW)	110	140	200	410
Annual Energy (MWHR)	445,000	490,000	535,000	700,000
Conventional BCR	.13	.54	.47	.34
Barrels of Oil Equivalent	627,895	691,390	754,885	987,700
Cost of Oil Equivalent	$10,046,320	$11,062,240	$12,078,160	$15,803,200
Energy Production Cost mils/kwhr	53	57	68	94
Annual Cost of Tidal Plant	$23,480,818	$27,885,666	$36,488,829	$65,915,451

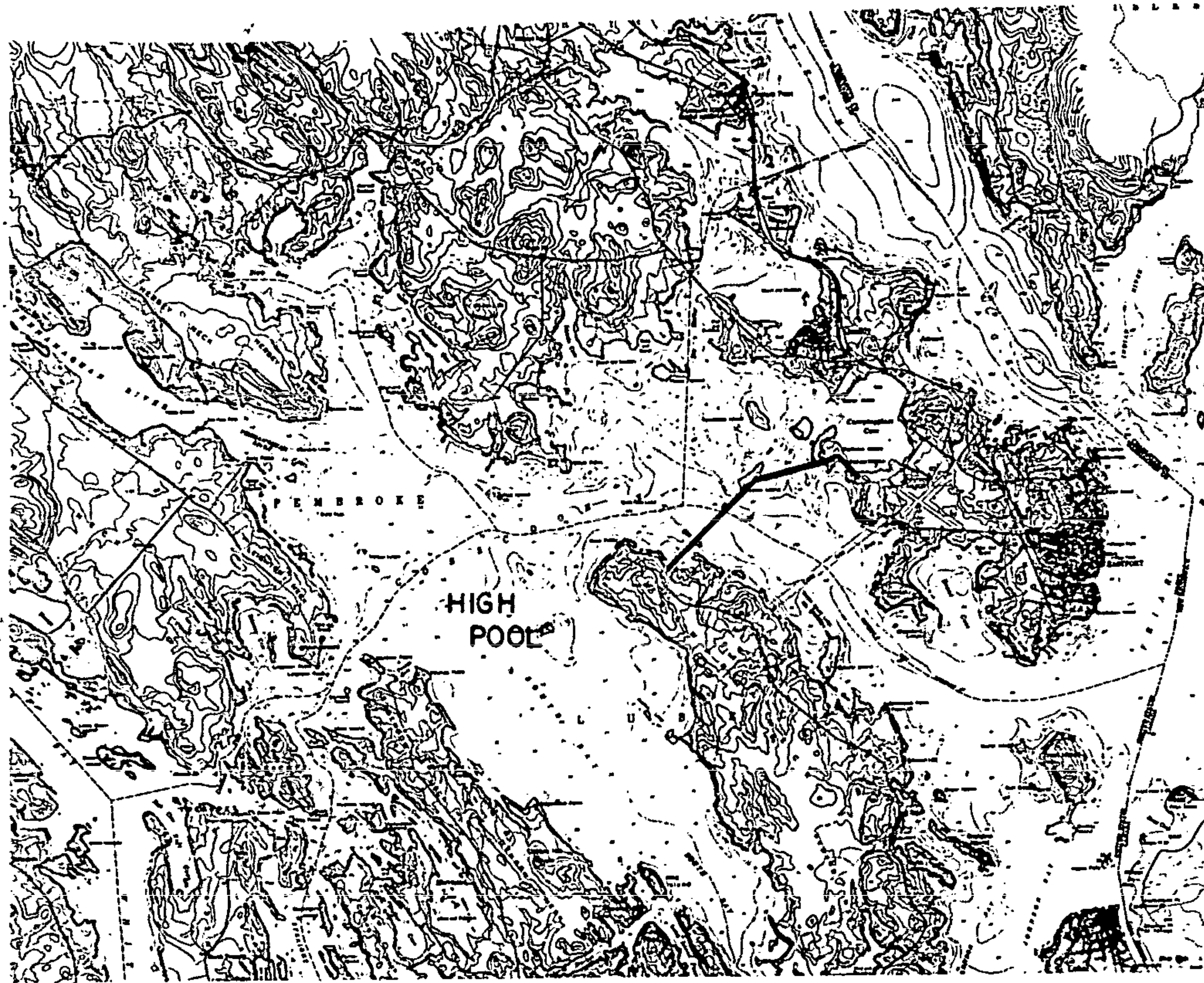
FIGURE II-2



CABLE

Capacity Factor	49	40	30	19
Installed Capacity (MW)	100	135	200	400
Annual Energy (MWHR)	430,000	475,000	520,000	680,000
Conventional BCR	.14	.54	.45	.34
Barrels of Oil Equivalent	606,730	644,827	733,720	959,480
Cost of Oil Equivalent	$ 9,707,680	$10,317,232	$11,739,520	$15,351,680
Energy Production Cost mils/kwhr	51	57	71	95
Annual Cost of Tidal Plant	$22,012,535	$27,281,208	$36,748,196	$64,644,095

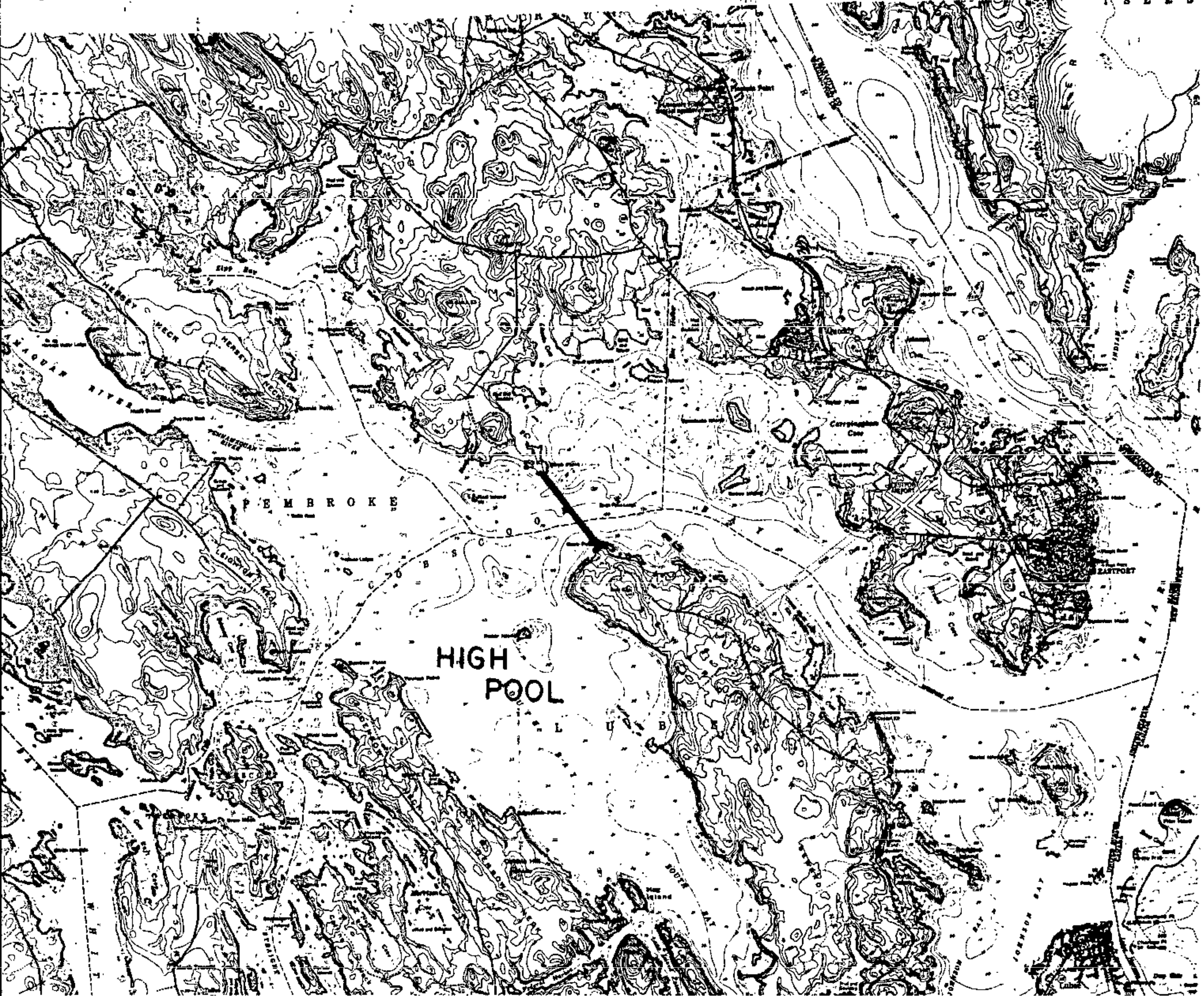
FIGURE II-3



GOOSE

Capacity Factor	49	40	30	20
Installed Capacity (MW)	100	135	195	385
Annual Energy (MWHR)	425,000	468,000	510,000	670,000
Conventional BCR	.14	.54	.47	.35
Barrels of Oil Equivalent	599,675	660,348	719,610	945,370
Cost of Oil Equivalent	$ 9,594,800	$10,565,568	$11,513,760	$15,125,920
Energy Production Cost mils/kwhr	51	57	69	93
Annual Cost of Tidal Plant	$21,604,272	$26,676,018	$35,082,255	$62,028,624

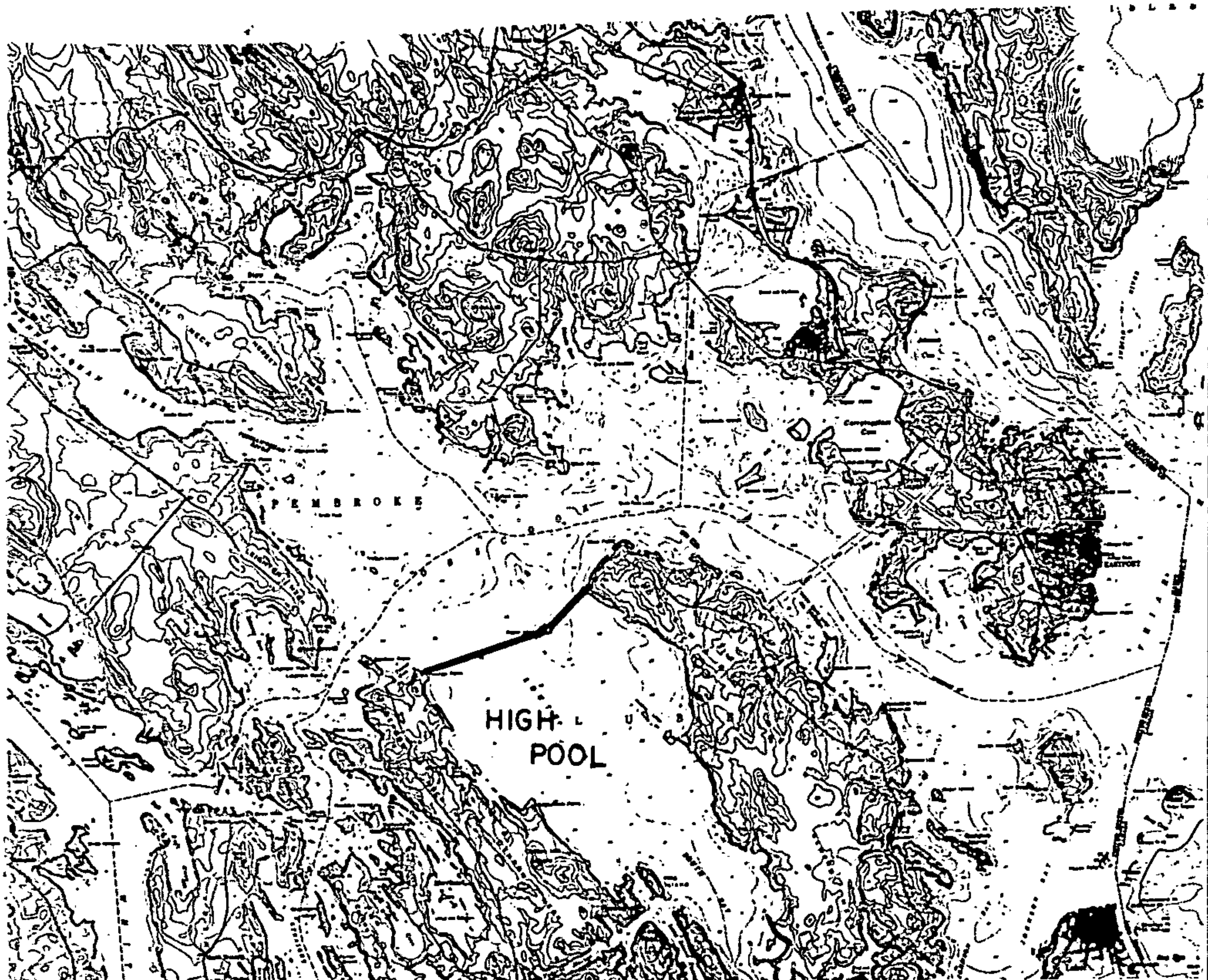
FIGURE II-4



BIRCH

Capacity Factor	47	38	29	20
Installed Capacity (MW)	85	110	165	320
Annual Energy (MWHR)	350,000	388,000	425,000	552,000
Conventional BCR	.13	.54	.44	.34
Barrels of Oil Equivalent	493,850	547,468	599,675	778,872
Cost of Oil Equivalent	$ 7,901,600	$ 8,759,488	$ 9,594,800	$12,461,952
Energy Production Cost mils/kwhr	53	57	70	94
Annual Cost of Tidal Plant	$18,470,048	$22,198,392	$29,937,731	$51,821,950

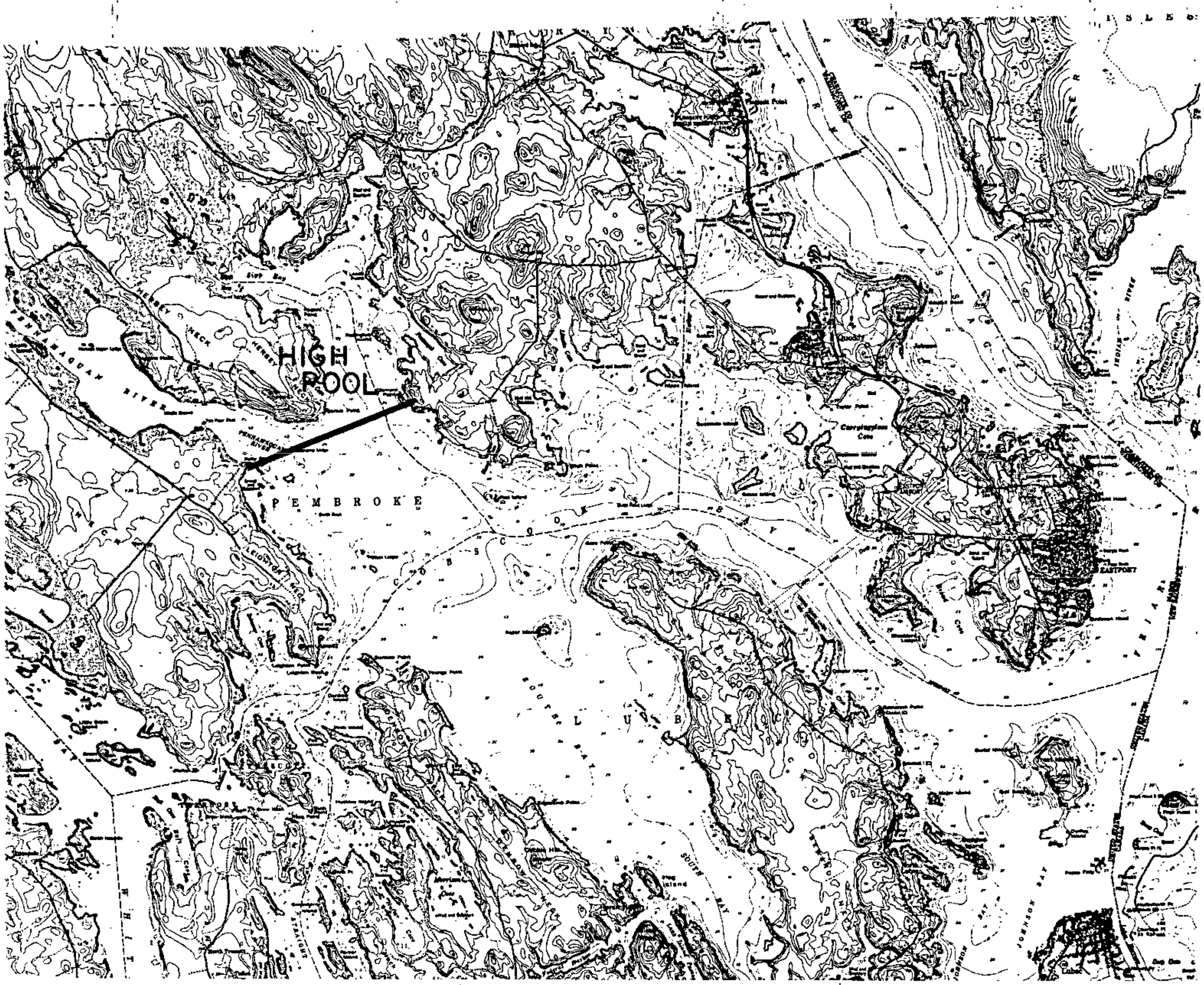
FIGURE II-5



RAZOR

Capacity Factor	47	38	29	20
Installed Capacity (MW)	20	26	40	70
Annual Energy (MWHR)	82,000	92,000	102,000	125,000
Conventional BCR	.07	.32	.29	.26
Barrels of Oil Equivalent	115,702	129,812	143,922	176,375
Cost of Oil Equivalent	$ 1,851,232	$ 2,076,992	$ 2,302,752	$ 2,822,000
Energy Production Cost mils/kwhr	95	96	106	119
Annual Cost of Tidal Plant	$ 7,826,303	$ 8,825,428	$10,782,081	$14,898,743

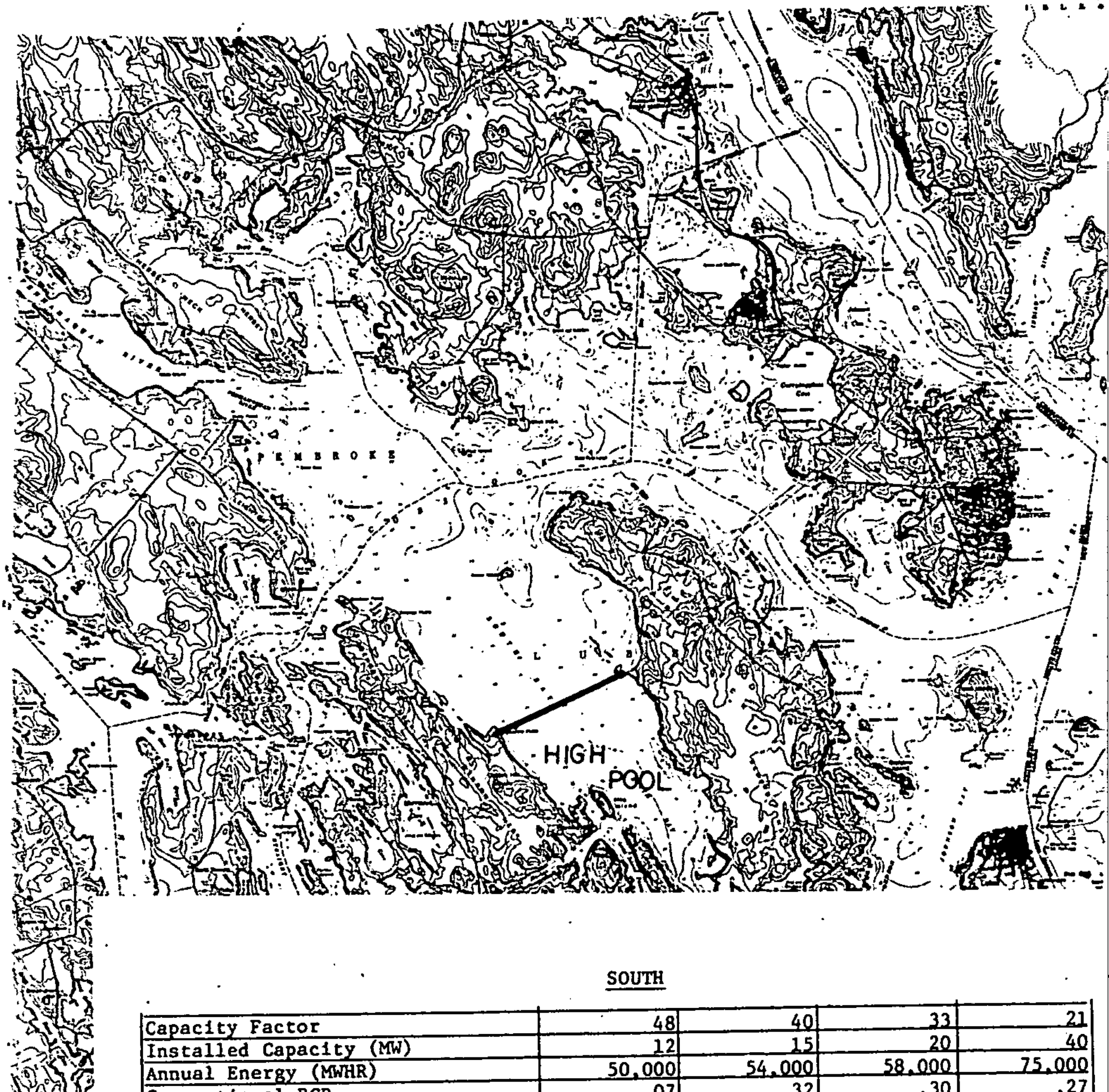
FIGURE II-6



EAST

Capacity Factor	49	40	34	23
Installed Capacity (MW)	12	16	20	40
Annual Energy (MWHR)	52,000	56,000	60,000	80,000
Conventional BCR	.07	.30	.29	.27
Barrels of Oil Equivalent	73,372	79,016	84,660	112,880
Cost of Oil Equivalent	$1,173,952	$1,264,256	$1,354,560	$1,806,080
Energy Production Cost mils/kwhr	98	103	105	114
Annual Cost of Tidal Plant	$5,097,852	$5,773,542	$6,305,139	$9,108,178

FIGURE II-7



SOUTH

Capacity Factor	48	40	33	21
Installed Capacity (MW)	12	15	20	40
Annual Energy (MWHR)	50,000	54,000	58,000	75,000
Conventional BCR	.07	.32	.30	.27
Barrels of Oil Equivalent	70,550	76,194	81,838	105,825
Cost of Oil Equivalent	$ 1,128,800	$ 1,219,104	$ 1,309,408	$ 1,693,200
Energy Production Cost mils/kwhr	97	98	103	117
Annual Cost of Tidal Plant	$ 4,848,091	$ 5,292,418	$ 5,959,316	$ 8,762,356

FIGURE II-8

PENNAMAQUAN

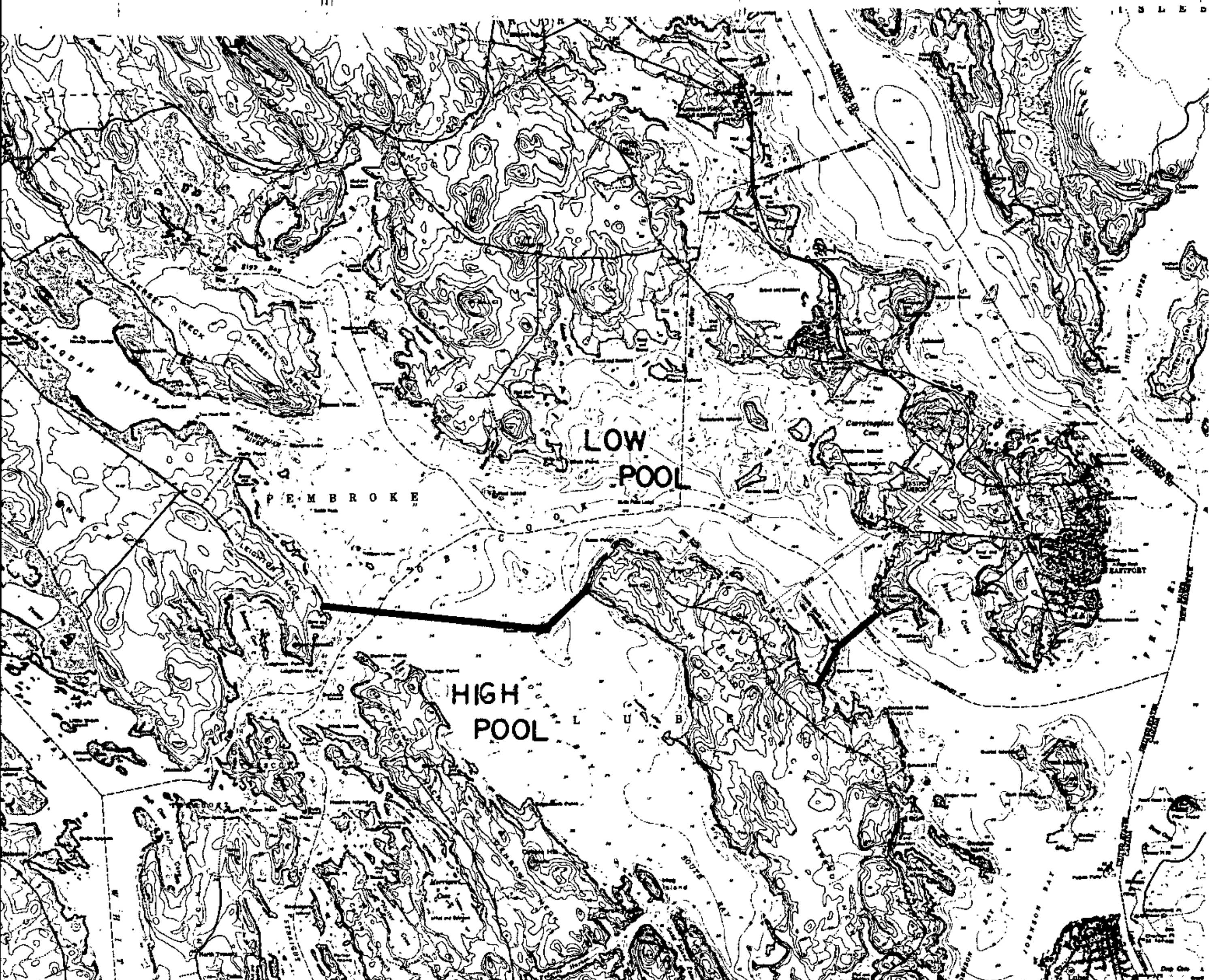
Capacity Factor	49	40	30	21
Installed Capacity (MW)	4	5	8	15
Annual Energy (MWHR)	17,000	19,000	21,000	27,000
Conventional BCR	.07	.30	.27	.23
Barrels of Oil Equivalent	23,987	26,809	29,631	38,097
Cost of Oil Equivalent	$ 383,792	$ 428,944	$ 474,096	$ 609,552
Energy Production Cost mils/kwhr	102	102	115	134
Annual Cost of Tidal Plant	$ 1,730,655	$ 1,936,497	$ 2,414,419	$ 3,613,333

FIGURE II-9

HALF MOON

Capacity Factor	46	38	29	19
Installed Capacity (MW)	4	5	8	15
Annual Energy (MWHR)	16,000	18,000	20,000	25,000
Conventional BCR	.07	.33	.28	.18
Barrels of Oil Equivalent	22,576	25,398	28,220	35,275
Cost of Oil Equivalent	$ 361,216	$ 406,368	$ 451,520	$ 564,400
Energy Production Cost mils/kwhr	94	95	110	169
Annual Cost of Tidal Plant	$ 1,507,291	$ 1,713,132	$ 2,191,055	$ 4,236,891

FIGURE II-10



TWO POOL

Capacity Factor	81	75	70	57
Installed Capacity (MW)	40 (15)	50 (18)	60 (20)	80 (25)
Annual Energy (MWHR)	285,000	330,000	370,000	400,000
Conventional BCR	.25	.27	.28	.29
Barrels of Oil Equivalent	402,135	465,630	522,070	564,400
Cost of Oil Equivalent	$ 6,434,160	$ 7,450,080	$ 8,353,120	$ 9,030,400
Energy Production Cost mils/kwhr	68	66	63	67
Annual Cost of Tidal Plant	$19,495,956	$21,680,546	$23,459,009	$26,619,714

FIGURE II-11

LINKED

	EAST-SOUTH		HALF MOON/PENNAMAQUAN	
Capacity Factor	47		46	
Installed Capacity (MW)	22 (7)		7 (2)	
Annual Energy (MWHR)	91,000		28,000	
Conventional BCR	.21		.17	
Barrels of Oil Equivalent	128,401		39,508	
Cost of Oil Equivalent	$2,054,416		$632,128	
Energy Production Cost mils/kwhr	103		124	
Annual Cost of Tidal Plant	$9,378,476		$3,468,065	

FIGURE II-12

DATA ON ALTERNATIVE PROJECTS

Dam	Approx. Capacity Factor %	Estimated Installed Capacity (MW)	Estimated Annual Energy (GWHR)	Impounded Area (Sq.Mi.) (High & Aver/2)	Gates Number	Gates Size (Sq.Ft.)
Dudley	48	120	500	36.2	24	30
	39	160	553		27	
	30	230	605		31	
	20	450	790		37	
Cooper	46	110	445	32.0	22	30
	39	140	490		24	
	31	200	535		27	
	19	410	700		34	
Cable	49	100	430	31.2	20	30
	40	135	475		23	
	30	200	520		27	
	19	400	680		33	
Goose	49	100	425	30.4	21	30
	40	135	468		23	
	30	195	570		25	
	20	385	670		33	
Birch	47	85	350	25.1	17	30
	38	110	388		19	
	29	165	425		21	
	20	320	552		27	
Razor	97	20	82	5.9	4	30
	38	26	92		6	28.5
	29	40	102		6	28.5
	20	70	125		6	30
South	48	12	50	3.56	3	27
	40	15	54		3	28.5
	33	20	58		3	28.5
	21	40	75		4	27.5
East	49	12	52	3.78	3	27
	40	16	56		3	28.5
	34	20	60		3	28.5
	23	40	80		4	27.5
Half Moon	46	4	16	1.17	2	20
	38	5	18		2	22
	29	8	20		2	22
	19	15	25		2	24
Pennamaquan	49	4	17	1.26	2	20
	40	5	19		2	22
	30	8	21		2	22
	21	15	27		2	24
Two	81	40 (15)	285	17.41 Low	22	30
	75	50 (17.5)	330	18.76 High	26	
	70	60 (20)	370		28	
	57	80 (25)	400		30	
Linked East-South	47	22 (7)	91	3.78 Low	2	30
				3.56 High	3	27
Linked Half Moon – Pennamaquan	46	7 (2.25)	28	1.26 Low	2	20
				1.17 High	2	17

FIGURE II-13

III. 1979 Project Cost Estimates

A. General

The primary purpose of this report is to determine the economic feasibility of several tidal power alternatives in Cobscook Bay. Representative construction, operation and maintenance costs for several new alternatives were needed for this effort. With the exception of two plans (a single pool plan and a two pool plan) detailed in 1935, no site specific detailed information was available for any alternative. To allow the screening of a large number of alternatives, several simplifying assumptions were made. These assumptions were applied uniformly for every alternative. No new detailed engineering analysis was undertaken for any part of this preliminary effort. Existing engineering data from previous studies were utilized to the maximum. The estimates derived by this preliminary effort are representative of the results one would expect after survey level studies. A brief description on the assumptions and criteria follows in Section III. B. Details of the relationships adopted can be found in Appendix II. Cost Estimation. Because of the large array of alternatives under consideration in conjunction with the need for some minor sensitivity analysis, a computer program (TIDAM) was developed to prepare cost estimates. A brief description of the program can be found in Section III. C. For more detailed information, see Appendix II. Representative estimates are presented in Section III. D.

B. Assumptions & Criteria Used for 1979 Preliminary Construction Cost Estimates

Dams

USGS topographic maps and NOAA Navigation Charts were used to obtain bay bottom information. Cross-sections of two typical types were considered for most dams. Both cross-section types assume a 2 to 1 side slope on the ocean side. Cross-section type 1 assumes a 4 to 1 side slope on the two pool side; while cross-section type 2 assumes a 2 to 1 side slope in the pool side. Volumes were calculated for many dams using average end area methods and average height methods for each type of section. Based on comparisons of the volumes, correction factors for use with the average height were developed and adopted. All dam volumes are based on a top-of-dam elevation of 25' NGVD (msl). Typical cross-sections of the dams are shown in Appendix II. All calculated dam volumes were increased by 25% for compaction and contingency. Comparisons of the "Dudley Dam" volume with volumes considered appropriate for the 1935 construction designs were made, and the newly calculated volumes did not differ significantly. Cost of dams (for all types of material in place), taken from the 1976 estimate of the International Plan (Stone & Webster) were averaged and updated using the Bureau of Reclamation index as furnished by the NED Estimating Section.

Navigational Locks

Costs of locks of various sizes from 1977 New England Division Economic Feasibility Report and experienced lock costs from the Charles River Dam were updated in accordance with NED Estimating Section and utilized. For Dudley Dam estimates, a navigational lock was used that has the following dimensions: 415' X 60' X 21' deep. For most other dams, a 95' X 25' X 12' navigational lock was used. For East and South Bays, a smaller lock was used. No locks were used in the Half Moon and Pennamaquan Alternatives.

Emptying and Filling Gates

Size, numbers, and costs of gates were specified for many alternatives in an interoffice memorandum dated 5 December 1978 (Appendix I). These data were furnished as part of a preliminary estimate of power, powerhouse costs, and hydraulic features. Relationships based on annual energy output were derived for the data presented in a 2 January 1979 interoffice memorandum (Appendix I) and were used to determine the cost, number, and size of gates required for additional alternatives.

Powerhouse

Revised estimates for slant turbines and powerhouses were provided in an interoffice memorandum dated 5 December 1978 (Appendix I). Estimates for bulb turbines and powerhouses were provided by the firm, Stone & Webster, in letter report dated 3 January 1979 (Appendix I). In accordance with NED Estimating Section, a cost of $220,000.00 per MW was added to both the slant and bulb estimates for excavation and cofferdamming for the powerhouse. Relationships for total costs per kilowatt (kw) of both bulb and slant turbines (and powerhouses) were developed and used for several alternatives. The exact locations for powerhouse, lock, fishway, and gates were not identified as part of this study. It appears, however, that Carrying Place Cove would be a suitable location for the powerhouse for the Dudley, Cooper, Cable and Goose alternatives.

Service Facilities

Costs for service facilities found in the 1977 Corps of Engineers and 1977 ERDA reports were considered appropriate, and a representative cost per kilowatt was adopted.

Relocations, Fishways, Real Estate and Service Equipment

Costs for these were found in the 1977 Corps of Engineers' report and representative values were selected and updated.

O&M, Major Replacement, Construction Time

Costs for O&M and Major Replacement were found in the 1977 Corps of Engineers' report. These costs were updated and unit costs per kilowatt were adopted. Construction times shown in the 1935 and 1977 estimates indicated that three (3) years was an appropriate time frame.

Transmission Lines

Costs for transmission were provided for specific selected size tidal power facilities in a preliminary report dated December 1978, prepared by the United States Department of Energy, Bonneville Power Administration. For alternatives for which no estimates were made, approximate relations were developed and utilized (see Appendix I).

C. The Cost Estimating Computer Program

The computer program, TIDAM, was developed in the New England Division to facilitate preparation of estimates for the large number of tidal power alternatives and variations considered. Basically, the program accepts externally calculated values for several parameters, prepares construction cost estimates and conventional BCR's. Basic values are input into files using an interactive file creation program called, "COBS". These files are then stored and later retrieved for use with TIDAM.

Using this system in conjunction with the previously described assumptions, it was possible to look at more than 100 tidal power alternatives quite rapidly. The sensitivity of total tidal power project costs was tested with respect to construction time, interest rates, dam size, lock size, turbine and powerhouse type, FERC power value, O&M cost, capacity factor, installed capacity, and several other parameters.

Listings of TIDAM, COBS, and a typical file are shown in Appendix II.

D. The Estimates

As previously mentioned, a large number of estimates have been prepared using several preliminary assumptions. A complete set of estimates can be found in Appendix II to this report.

Several typical cost estimates are presented on the following pages. These include: a single pool alternative with a high capacity factor; an optimum BCR large single pool alternative; a two pool alternative; and optimum small single pool alternative; and a linked basin alternative.

2 CABLE 49 100 L1 B   TOPWIDTH= 50 FT   X-SECTION TYPE 2

COST OF MATERIAL IN PLACE	$ 4.50 /CY
VOLUME OF DAM	5400000. CY
COST OF LOCKS	$ 7000000.
NUMBER OF GATES	20
UNIT PRICE OF GATE	$2050000.
INSTALLED CAPACITY	100. MW
DEPENDABLE CAPACITY	0. MW
ANNUAL ENERGY	430000200. KWH
COST OF POWERHOUSE	$133700000.
UNIT PRICE OF SERVICE FACILITY	$ 7.50 /KW
COST OF RELOCATION	$ 8500000.
COST OF FISHWAY	$ 2300000.
CONTINGENCY	0.15
ED & S&A	0.10
COST OF REAL ESTATE	$1300000.
COST OF SERVICE EQUIPMENT	$ 600000.
CONSTRUCTION INTEREST RATE	0.06875
CRF INTEREST	0.06875
CONSTRUCTION TIME	3. YRS
CAPACITY VALUE	$ 0.00
ENERGY VALUE	7. MIL/KWH
UNIT O & M	$ 7.00 /KW
UNIT MAJOR REPLACEMENT	$ 2.70 /KW
PROJECT LIFE	100. YRS

DAMS	$ 24300000.
LOCKS	$ 7000000.
GATES	$ 41000000.
POWERHOUSE	$ 133700000.
SERVICE FACILITIES	$ 750000.
RELOCATION	$ 8500000.
FISHWAYS	$ 2300000.
BASIC COST	$ 217550000.
WITH CONTINGENCY	$ 250182500.
WITH ED & SA	$ 275200750.
REAL ESTATE	$ 1300000.
SERVICE EQUIPMENT	$ 600000.
INTEREST DURING CONSTRUCTION	$ 28576015.
PROJECT COST	$ 277100750.
COST OF INVESTMENT	$ 305676765.
ANNUAL INVESTMENT COST	$ 21042535.
OPERATION & MAINTENANCE	$ 700000.
MAJOR REPLACEMENT COST	$ 270000.
ANNUAL COST	$ 22012535.
ANNUAL BENEFITS	$ 3010001.
BENEFIT/COST RATIO	0.14
ENERGY COST	51. MIL/KWH

4 COOPER 39 140 L1 B TOPWIDTH= 50 FT X-SECTION TYPE 2

COST OF MATERIAL IN PLACE	$ 4.50 /CY
VOLUME OF DAM	4800000. CY
COST OF LOCKS	$ 7000000.
NUMBER OF GATES	24
UNIT PRICE OF GATE	$2050000.
INSTALLED CAPACITY	140. MW
DEPENDABLE CAPACITY	0. MW
ANNUAL ENERGY	490000200. KWH
COST OF POWERHOUSE	$185000000.
UNIT PRICE OF SERVICE FACILITY	$ 7.50 /KW
COST OF RELOCATION	$ 8500000.
COST OF FISHWAY	$ 2300000.
CONTINGENCY	0.15
ED & S&A	0.10
COST OF REAL ESTATE	$1300000.
COST OF SERVICE EQUIPMENT	$ 600000.
CONSTRUCTION INTEREST RATE	0.06875
CRF INTEREST	0.06875
CONSTRUCTION TIME	3. YRS
CAPACITY VALUE	$ 0.00
ENERGY VALUE	31. MIL/KWH
UNIT O & M	$ 7.00 /KW
UNIT MAJOR REPLACEMENT	$ 2.70 /KW
PROJECT LIFE	100. YRS

DAMS	$ 21600000.
LOCKS	$ 7000000.
GATES	$ 49200000.
POWERHOUSE	$ 185000000.
SERVICE FACILITIES	$ 1050000.
RELOCATION	$ 8500000.
FISHWAYS	$ 2300000.
BASIC COST	$ 274650000.
WITH CONTINGENCY	$ 315847500.
WITH ED & SA	$ 347432250.
REAL ESTATE	$ 1300000.
SERVICE EQUIPMENT	$ 600000.
INTEREST DURING CONSTRUCTION	$ 36024888.
PROJECT COST	$ 349332250.
COST OF INVESTMENT	$ 385357138.
ANNUAL INVESTMENT COST	$ 26527666.
OPERATION & MAINTENANCE	$ 980000.
MAJOR REPLACEMENT COST	$ 378000.
ANNUAL COST	$ 27885666.
ANNUAL BENEFITS	$ 15190006.
BENEFIT/COST RATIO	0.54
ENERGY COST	57. MIL/KWH

S TWO 57 80 L1 B TOPWIDTH= 50 FT X-SECTION TYPE 2

COST OF MATERIAL IN PLACE	$ 4.50 /CY
VOLUME OF DAM	13800000. CY
COST OF LOCKS	$ 14000000.
NUMBER OF GATES	30
UNIT PRICE OF GATE	$2050000.
INSTALLED CAPACITY	80. MW
DEPENDABLE CAPACITY	25. MW
ANNUAL ENERGY	400000000. KWH
COST OF POWERHOUSE	$108100000.
UNIT PRICE OF SERVICE FACILITY	$ 7.50 /KW
COST OF RELOCATION	$ 8500000.
COST OF FISHWAY	$ 4600000.
CONTINGENCY	0.15
ED & S&A	0.10
COST OF REAL ESTATE	$1300000.
COST OF SERVICE EQUIPMENT	$ 600000.
CONSTRUCTION INTEREST RATE	0.06875
CRF INTEREST	0.06875
CONSTRUCTION TIME	4. YRS
CAPACITY VALUE	$ 195.00
ENERGY VALUE	7. MIL/KWH
UNIT O & M	$ 7.00 /KW
UNIT MAJOR REPLACEMENT	$ 2.70 /KW
PROJECT LIFE	100. YRS

DAMS	$ 62100000.
LOCKS	$ 14000000.
GATES	$ 61500000.
POWERHOUSE	$ 108100000.
SERVICE FACILITIES	$ 600000.
RELOCATION	$ 8500000.
FISHWAYS	$ 4600000.
BASIC COST	$ 259400000.
WITH CONTINGENCY	$ 298310000.
WITH ED & SA	$ 328141000.
REAL ESTATE	$ 1300000.
SERVICE EQUIPMENT	$ 600000.
INTEREST DURING CONSTRUCTION	$ 45380637.
PROJECT COST	$ 330041000.
COST OF INVESTMENT	$ 375421637.
ANNUAL INVESTMENT COST	$ 25843714.
OPERATION & MAINTENANCE	$ 560000.
MAJOR REPLACEMENT COST	$ 216000.
ANNUAL COST	$ 26619714.
ANNUAL BENEFITS	$ 7675000.
BENEFIT/COST RATIO	0.29
ENERGY COST	67. MIL/KWH

4 PENNAMAQUAN 40 5 B TOPWIDTH= 30 FT X-SECTION TYPE 2

COST OF MATERIAL IN PLACE	$ 6.00 /CY
VOLUME OF DAM	650000. CY
COST OF LOCKS	$ 0.
NUMBER OF GATES	2
UNIT PRICE OF GATE	$1100000.
INSTALLED CAPACITY	5. MW
DEPENDABLE CAPACITY	0. MW
ANNUAL ENERGY	19000000. KWH
COST OF POWERHOUSE	$ 8200000.
UNIT PRICE OF SERVICE FACILITY	$ 7.50 /KW
COST OF RELOCATION	$ 4000000.
COST OF FISHWAY	$ 1000000.
CONTINGENCY	0.15
ED & S&A	0.10
COST OF REAL ESTATE	$1000000.
COST OF SERVICE EQUIPMENT	$ 200000.
CONSTRUCTION INTEREST RATE	0.06875
CRF INTEREST	0.06875
CONSTRUCTION TIME	2. YRS
CAPACITY VALUE	$ 0.00
ENERGY VALUE	31. MIL/KWH
UNIT O & M	$ 7.00 /KW
UNIT MAJOR REPLACEMENT	$ 2.70 /KW
PROJECT LIFE	100. YRS

DAMS	$	3900000.
LOCKS	$	0.
GATES	$	2200000.
POWERHOUSE	$	8200000.
SERVICE FACILITIES	$	37500.
RELOCATION	$	4000000.
FISHWAYS	$	1000000.
BASIC COST	$	19337500.
WITH CONTINGENCY	$	22238125.
WITH ED & SA	$	24461937.
REAL ESTATE	$	1000000.
SERVICE EQUIPMENT	$	200000.
INTEREST DURING CONSTRUCTION	$	1764258.
PROJECT COST	$	25661937.
COST OF INVESTMENT	$	27426196.
ANNUAL INVESTMENT COST	$	1887997.
OPERATION & MAINTENANCE	$	35000.
MAJOR REPLACEMENT COST	$	13500.
ANNUAL COST	$	1936497.
ANNUAL BENEFITS	$	589000.
BENEFIT/COST RATIO		0.30
ENERGY COST		102. MIL/KWH

4 EAST SOUTH 47 22 L B TOPWIDTH= 50 FT X-SECTION TYPE 2

COST OF MATERIAL IN PLACE	$ 4.50 /CY
VOLUME OF DAM	6600000. CY
COST OF LOCKS	$ 8000000.
NUMBER OF GATES	5
UNIT PRICE OF GATE	$1820000.
INSTALLED CAPACITY	22. MW
DEPENDABLE CAPACITY	7. MW
ANNUAL ENERGY	91000000. KWH
COST OF POWERHOUSE	$ 33700000.
UNIT PRICE OF SERVICE FACILITY	$ 7.50 /KW
COST OF RELOCATION	$ 8000000.
COST OF FISHWAY	$ 2000000.
CONTINGENCY	0.15
ED & S&A	0.10
COST OF REAL ESTATE	$2000000.
COST OF SERVICE EQUIPMENT	$4000000.
CONSTRUCTION INTEREST RATE	0.06875
CRF INTEREST	0.06875
CONSTRUCTION TIME	3. YRS
CAPACITY VALUE	$ 195.00
ENERGY VALUE	7. MIL/KWH
UNIT O & M	$ 7.00 /KW
UNIT MAJOR REPLACEMENT	$ 2.70 /KW
PROJECT LIFE	100. YRS

DAMS	$ 29700000.
LOCKS	$ 8000000.
GATES	$ 9100000.
POWERHOUSE	$ 33700000.
SERVICE FACILITIES	$ 165000.
RELOCATION	$ 8000000.
FISHWAYS	$ 2000000.
BASIC COST	$ 90665000.
WITH CONTINGENCY	$ 104264750.
WITH ED & SA	$ 114691225.
REAL ESTATE	$ 2000000.
SERVICE EQUIPMENT	$ 4000000.
INTEREST DURING CONSTRUCTION	$ 12446283.
PROJECT COST	$ 120691225.
COST OF INVESTMENT	$ 133137508.
ANNUAL INVESTMENT COST	$ 9165076.
OPERATION & MAINTENANCE	$ 154000.
MAJOR REPLACEMENT COST	$ 59400.
ANNUAL COST	$ 9378476.
ANNUAL BENEFITS	$ 2002000.
BENEFIT/COST RATIO	0.21
ENERGY COST	103. MIL/KWH

The following general observations appear to be applicable:

- Since the alternative for linked or multipool configurations is nuclear power, and since an installed capacity that is approximately 3 - 4 times the dependable capacity is required, it appears that such schemes are not feasible.

- Since schemes with dependable capacity are so expensive, a tidal power project should be designed to maximize energy (plant factor) rather than dependable capacity.

- Single pool alternatives with large areas of the bay impounded and relatively small installed capacities (high capacity factor) yield the greatest economic (energy) advantage.

- Since FERC's cut-off between combined cycle (31 mils/kwhr) and nuclear power (7 mils/kwhr) as an alternative occurs as a 40% capacity factor, tidal plants are not economical at a greater than 40% capacity factor.

- Use of bulb turbines in lieu of slant turbines raise BCR by approximately 0.05.

- Under present FERC policy, using the preliminary estimates (with approximate transmission cost added), optimum conventional BCR's are 0.5 to 1.0.

- Since tidal power is reliable, though not dependable, in the Hydroelectric sense, it seems that at some future time, FERC may allow a capacity credit for Tidal Power. If this occurs, different alternatives will probably yield optimum BCR's; that is, alternatives with larger installed capacities.

The study investigated approximately 90 different tidal power alternatives, utilizing both slant and bulb-type turbine and generator equipment. The bulb-type units are less costly than the slant type equipment and require smaller power houses.

The sizes of alternative projects ranged from 5 to 450 megawatts with annual power output of 16 to 790 million kilowatt hours per year. The construction cost of the projects ranged from approximately $22,000,000 to $916,000,000. The projects have approximate annual operation and maintenance costs varying between $1,500,000 and $85,000,000. The approximate annual power benefits varied between $112,000 and $25,000,000 per year for the range of projects.

IV. Relative Price Shift Analysis

A. Introduction

In September of 1976 Governor Longley of Maine requested that the New England Division evaluate Passamaquoddy tidal power on the basis of life cycle cost analysis. The following technical definition explaining life cycle costing has been extracted from the General Provisions of Armed Services Regulation dated 21 May 1976:

> "The life cycle cost of a system or item of equipment is the total cost to the Government of acquisition and ownership of that system or item of equipment over its full life. It includes the cost of development, acquisition, operation, support and where applicable, disposal. Since the cost of operating and supporting the system or equipment over its useful life is substantial and, in many cases, greater than the acquisition cost, it is essential that such costs be considered in development and acquisition decisions in order that proper consideration can be given to those systems or equipment that will result in the lowest life cycle cost to the Government."

The conventional benefit-to-cost ratio calculated by the Corps of Engineers takes account of total costs throughout the life of the project - i.e. maintenance, operation, rehabilitation, in today's prices. Life cycle costing varies from the traditional methodology utilized by the Corps in evaluating water resource projects by projecting unit-cost prices into the future.

B. Preliminary Life Cycle Cost Analysis

In response to the Governor's request the Corps of Engineers performed a preliminary life cycle cost analysis, beginning in late 1976 and extending into 1977, on the 500MW international Passamaquoddy project. The analysis employed a computer model for life cycle cost studies based upon the model described in Chapter VI of the U.S. Department of Commerce, National Technical Information Service Report AD/A-018 dated July 1975, entitled "Hydroelectric Power Potential at Corps of Engineers Projects." The Federal Power Commission (now the Federal Energy Regulatory Commission, FERC) utilizing the model furnished the necessary expertise and analysis.

In applying the computer model the 500 MW international tidal power project was compared to its most probable alternative as determined by the Federal Power Commission, a combined cycle plant. The model allowed escalation rates for five cost variables - operation and maintenance, generating plant, substation, transmission lines, and fuel; to be input. Annual escalation rates of 3, 5, and 7 percent were selected to reflect a range of increases in costs and were applied to each of the five variables. Utilizing this input the information on the escalation of the annual cost of the tidal project and its alternative as a function of time, presented in figures 1, 2, and 3, was derived. These figures are based upon a project life of 100 years for the 500 MW international Passamaquoddy tidal power project and the assumption that the project went on line in June 1976 with annual costs of $121,121,000 and production of 1,932,000,000 kwh/year. For comparison purposes, both the alternative and the tidal power project were assumed to be financed at 6-3/8%.

In escalating power benefits (the alternative's cost) and project costs, the former increase at a more rapid rate in this analysis. The principal reasons for this are: (1) the change in the depreciation rate of the alternative plant; and (2) the reliance of the alternative upon a fuel which increases in price as it becomes increasingly scarce.

The sharp jumps in the curves (figures 1-3) associated with the alternative project result from the shorter life span of the alternative vis a vis the tidal project. This shorter life results in a change in the fixed depreciation charge needed to cover the initial cost of the thermal project whose cost is increasing by $(1+i)^{30}$ at each replacement, where i is the escalation rate and 30 is the life of the alternative. Due to the escalation in costs assumed to take place every year, the cost of building the combined cycle plant increases with each installation, and therefore the depreciation charge increases.

Figure 4 displays the impact of the various escalation rates upon the benefit to cost ratio of the project, and it is apparent that under the method employed in this study an escalation rate of approximately four percent is required for the project to reach a break-even level over its life time.

Line projections for annual power benefits and costs intersect after a period of project operation and the benefit/cost ratio for that point is 1.0. The following indicates the year of this intersection for each escalation rate:

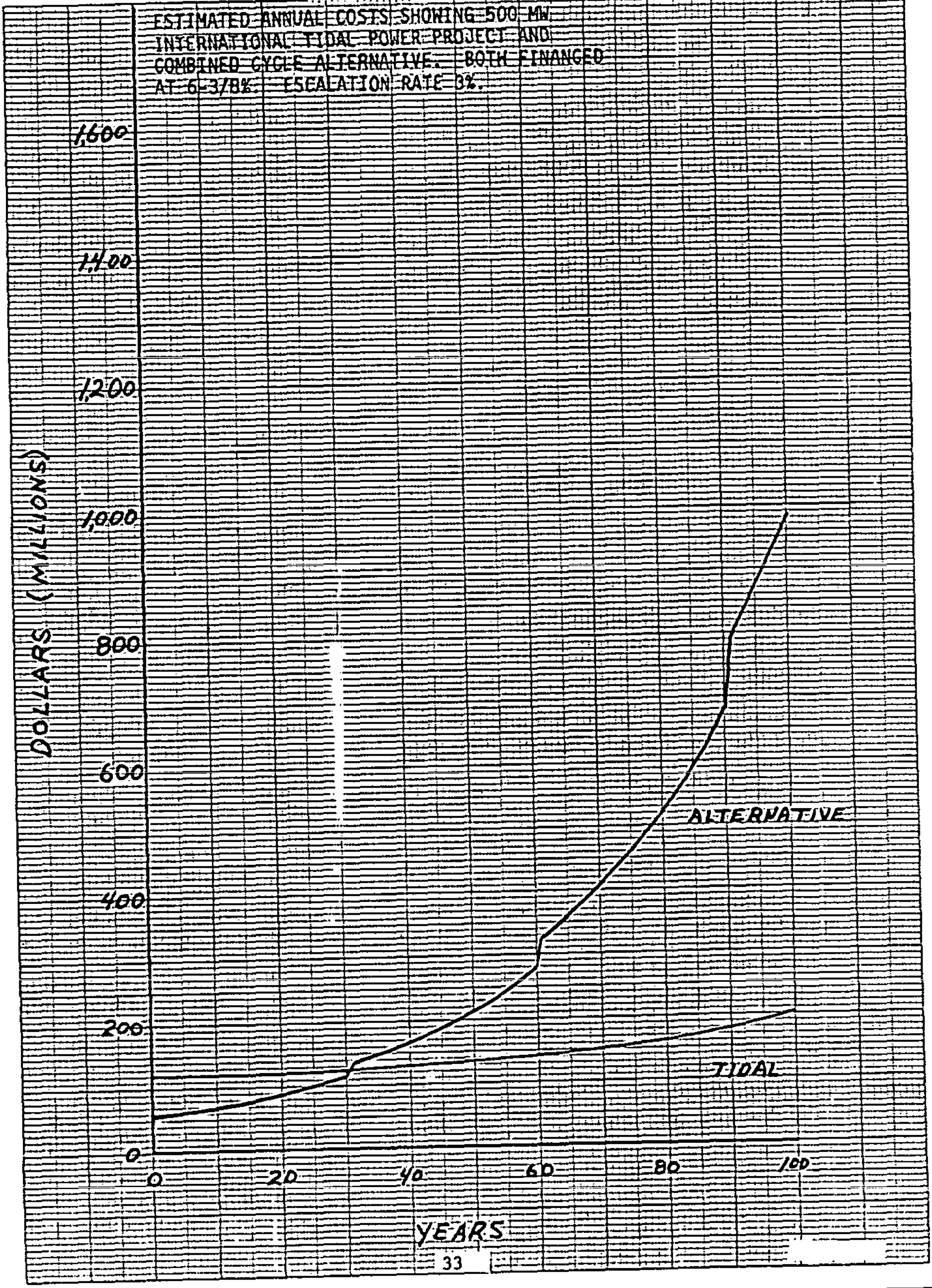
Escalation Rate	Year BCR = 1.0
3%	31
5%	20
7%	15

TABLE 1

Life-Cycle Analysis of
500 MW International Tidal Power Project
(Both Plants Financed at 6-3/8%)

Interstate	Escalation Rate	Plant Type	Total Present Worth (6-3/8% Discount Rate)	Annual Cost (Using CRF 100 Yrs. 6-3/8%	Levelized Cost (Mills/KWH)	Life Cycle B/C Ratio (Power Benefits)
6-3/8%	3%	Alternative	$1,491,758,000	$ 95,294,000	49.3	.76
6-3/8%	3%	Tidal	1,958,832,000	125,130,000	64.8	
6-3/8%	5%	Alternative	2,731,104,000	174,463,000	90.3	1.32
6-3/8%	5%	Tidal	2,072,210,000	132,373,000	68.5	
6-3/8%	7%	Alternative	6,531,940,000	417,260,000	216.0	2.70
6-3/8%	7%	Tidal	2,420,867,000	154,645,000	80.0	

Figure 1


ESTIMATED ANNUAL COSTS SHOWING 500 MW INTERNATIONAL TIDAL POWER PROJECT AND COMBINED CYCLE ALTERNATIVE. BOTH FINANCED AT 6-3/8%. ESCALATION RATE 3%.
DOLLARS (MILLIONS)
1,600
1,400
1,200
1,000
800
600
400
200
0
ALTERNATIVE
TIDAL
0
20
40
60
80
100
YEARS

ESTIMATED ANNUAL COSTS SHOWING 500 MW INTERNATIONAL TIDAL POWER PROJECT AND COMBINED CYCLE ALTERNATIVE. BOTH FINANCED at 6-3/8%. ESCALATION RATE 5%.

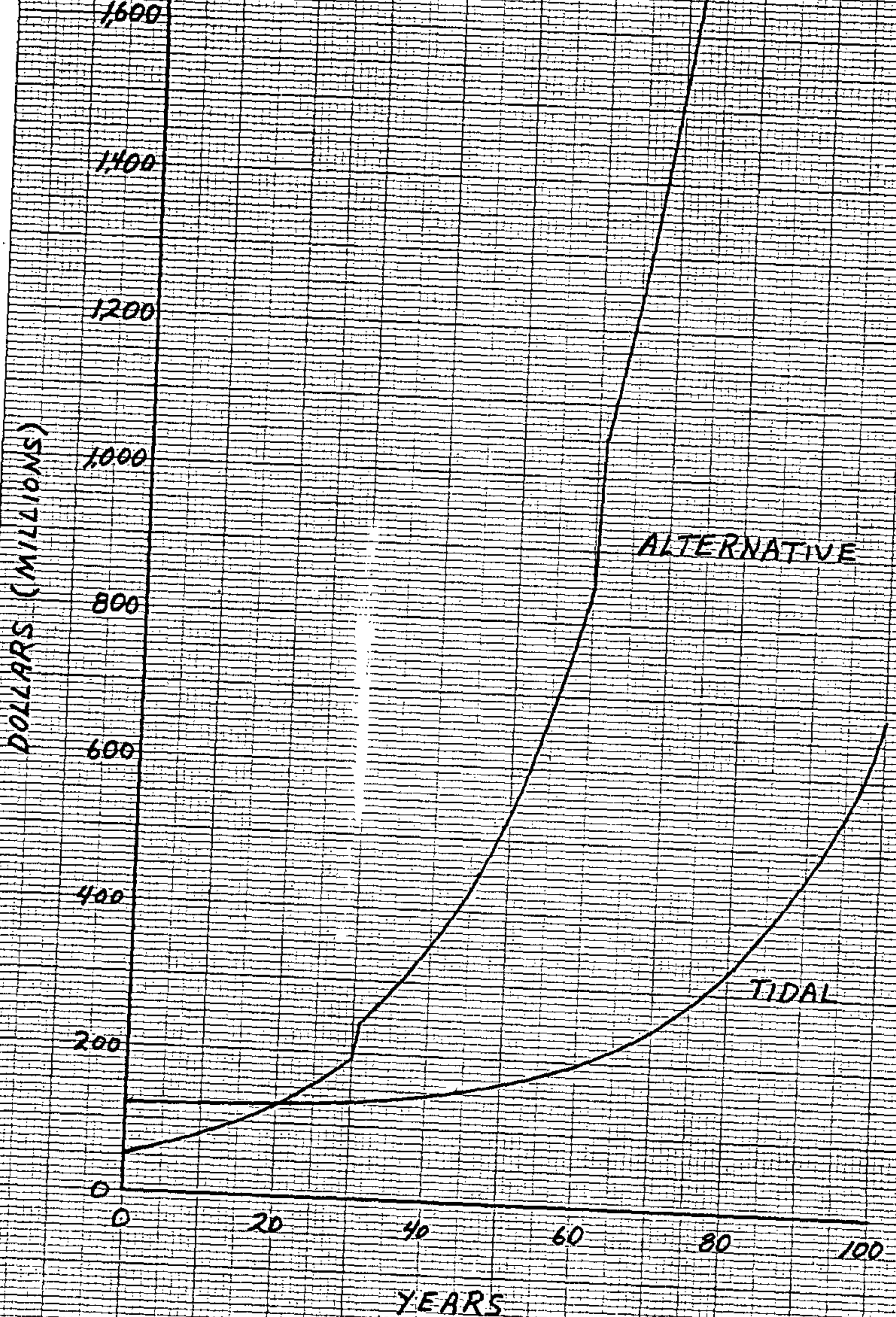


Figure 3

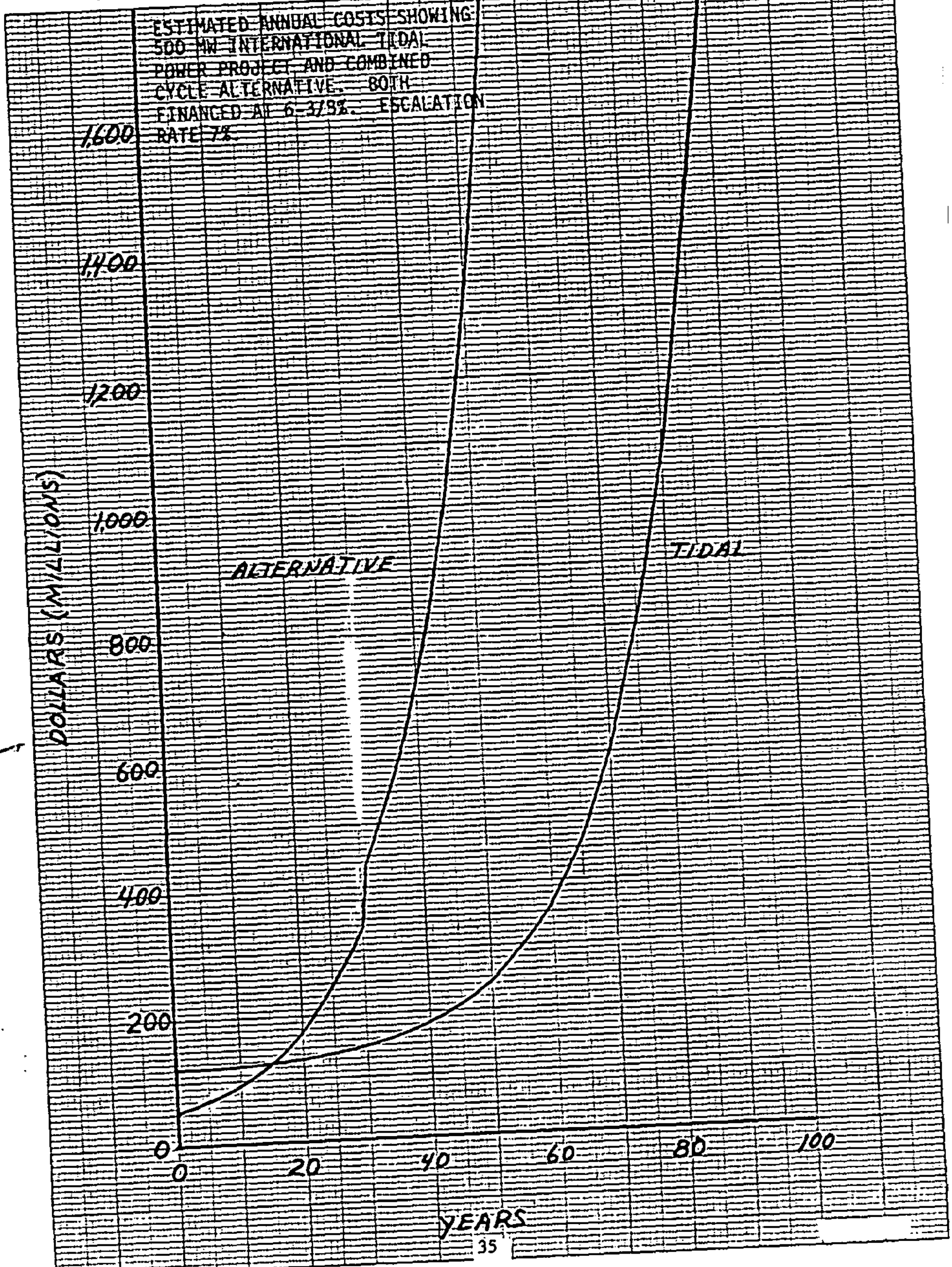
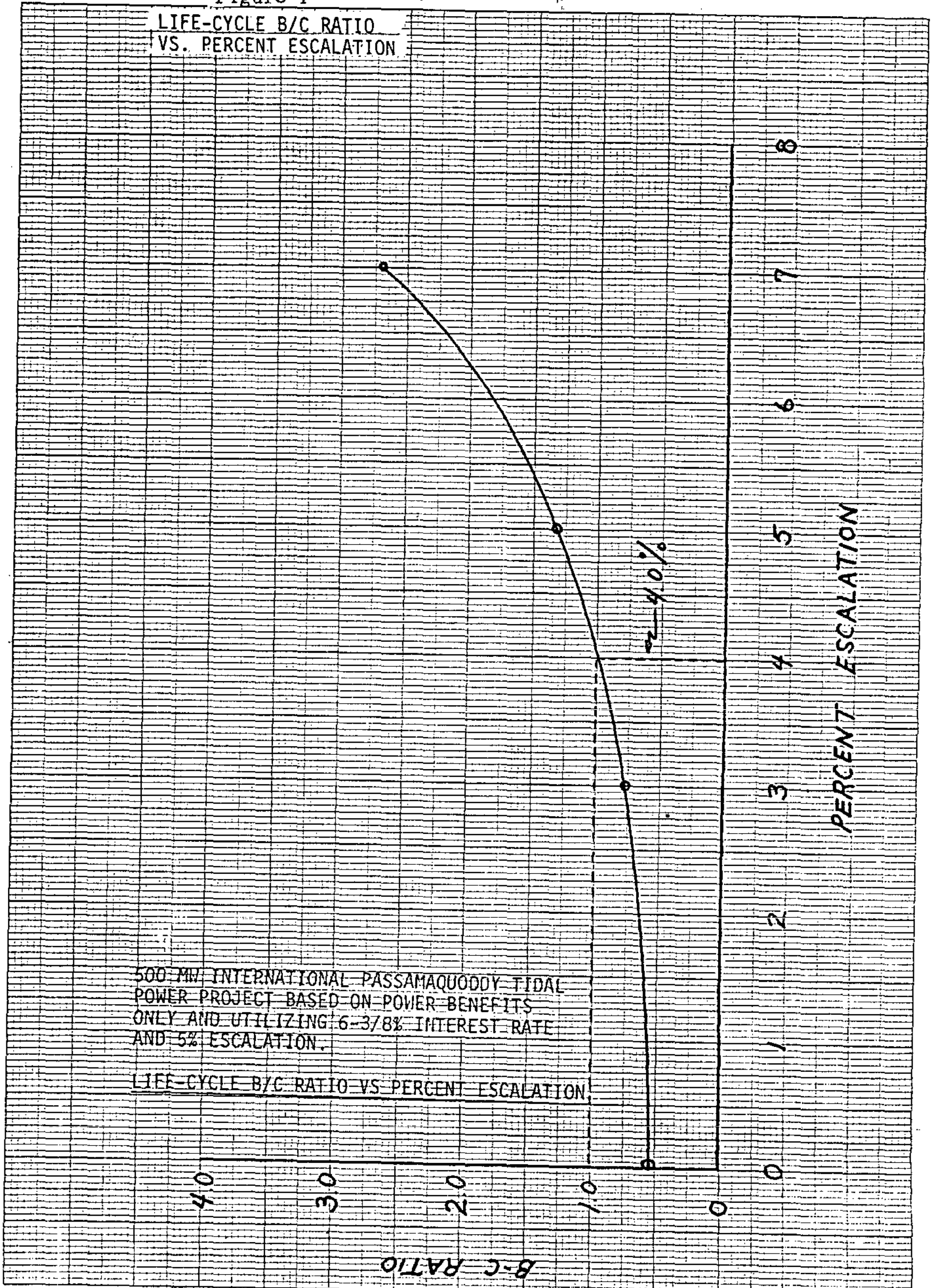

ESTIMATED ANNUAL COSTS SHOWING 500 MW INTERNATIONAL TIDAL POWER PROJECT AND COMBINED CYCLE ALTERNATIVE. BOTH FINANCED AT 6-3/8%. ESCALATION RATE 7%
1,600
1,400
1,200
1,000
800
600
400
200
0
DOLLARS (MILLIONS)
ALTERNATIVE
TIDAL
0
20
40
60
80
100
YEARS

Figure 4



LIFE-CYCLE B/C RATIO
VS. PERCENT ESCALATION
500 MW INTERNATIONAL PASSAMAQUODDY TIDAL
POWER PROJECT BASED ON POWER BENEFITS
ONLY AND UTILIZING 6-3/8% INTEREST RATE
AND 5% ESCALATION.
LIFE-CYCLE B/C RATIO VS PERCENT ESCALATION
≈4.0%
PERCENT ESCALATION
0
1
2
3
4
5
6
7
8
B-C RATIO
0
1.0
2.0
3.0
4.0

After the intersection point the project begins to accrue net benefits, but as indicated by the benefit to cost ratio for an escalation rate of 3 percent in table 1, these net benefits may not compensate for the net losses experienced prior to the intersection point.

On the basis of this preliminary report, submitted to OCE in 1978, NED was authorized to proceed with the Plan of Study while revising the initial life cycle cost analysis. In particular, the use of escalation factors including general inflation and applied across all project features, as was done in the preliminary life cycle analysis, was found not to be in accordance with existing regulations and needed refinement. The authorizing document pointed out that while the inclusion of general inflation is not valid in economic analysis under the Principles and Guidelines set by the Water Resources Council, the use of relative price changes is. The reasoning behind this will be discussed in the following section.

C. Relative Price Shift Analysis

Methodology.

Relative price shift analysis goes beyond a static benefit to cost comparison by considering changes in underlying (real) price relationships that might occur over the life of the project. (The term 'relative price shift' will be used in place of 'life cycle costing' throughout this report. This term is felt to be more descriptive of the analysis performed.) The use of relative price shifts is discussed in the Water Resources Council "Establishment of Principles and Standards for Planning" (pages 10 and 11):

> "When prices are used in evaluation they should reflect the real exchange values expected to prevail over the period of analysis. For this purpose, relative price relationships and the general level of prices prevailing during the planning study will be assumed to hold generally for the future, except where specific studies and considerations indicate otherwise."

The focus on real price relationships, net of general inflation, is important. The basic rationale for this approach is as follows: the monetary value of any good is ultimately valued in reference to other goods (goods refer to all things of value - i.e. labor, material goods) available in the market place. If all goods inflated at the same rate, then in effect their value would not be altered. By concentrating on relative price changes, we are considering fundamental changes in the valuation of that good. (In reality, however, inflation is not so evenhanded, since many things, i.e. fixed pensions, debts, are not altered by inflation. Thus, there is always some distortion involved in the valuation of certain goods.)

a. Discount Rate

In the utilization of relative price shift methodology it is necessary to discount benefit and cost flows at rates which exclude the premium associated with inflationary expectations. Charles W. Howe in his book for the Water Resource Monograph Series entitled "Benefit-Cost Analysis for Water System Planning" discusses this rather complex problem in a very easy to understand way:

> "Consider a project having an initial construction cost of C_0 and a sequence of annual benefits and costs of B_1, C_1; B_2, C_2; ...; B_n, C_n. Let us suppose that these benefits and costs have been computed in terms of construction period prices. Let i be the discount rate that would be applicable in the face of steady prices. Then the present value of net benefits is given by

$$PVNB = -C_0 + \frac{(B_1 - C_1)}{(1 + i)} + \frac{(B_2 - C_2)}{(1 + i)^2} + \ldots + \frac{(B_n - C_n)}{(1 + i)^n} \qquad (A1)$$

Now suppose that a rate of general inflation of i per year exists. Two things will happen: (1) the B_n and C_n values will increase over time above the values given in equation A1, and (2) the discount rate is likely to incorporate an inflationary premium (i.e., interest rates will increase to protect lenders from a loss of purchasing power on the funds they lend). The latter will certainly occur if the discount rate is derived from the market rates of interest. Let this discount rate be designated r. Then the present value of net benefits as calculated becomes

$$PV = -C_0 + \frac{(B_1 - C_1)(1 + i)}{(1 + r)} + \ldots + \frac{(B_n - C_n)(1 + i)^n}{(1 + r)^n} \qquad (A2)$$

Since the inflationary premium in the discount rate is such that $(1 + r) = (1 + i)(1 + i)$ when the market rates of interest fully compensate for inflation, equation A2 can be rewritten as

$$PV = -C_0 + \frac{(B_1 - C_1)(1 + i)}{(1 + i)(1 + i)} + \ldots + \frac{(B_n - C_n)(1 + i)^n}{(1 + i)^n(1 + i)^n} \qquad (A3)$$

Clearly, the inflationary terms cancel out, and we are left with the same expression as that in equation A1.

Thus we conclude that, in the case of general inflation, it makes no difference whether we use (1) benefits and costs all stated in construction period prices and a discount rate containing no inflationary premium, or (2) benefits and costs in the prices of the period in which each is incurred and a discount factor that fully compensates for the rate of inflation."[1]

Since the relative price shift methodology states benefits and costs in current prices with only real economic value changes considered, Howe's analysis leads to a discount rate containing no inflationary premium as being appropriate for this analysis.

The determination of inflation free discount rates for the privately financed alternative and the Federally financed project is, however, very difficult. This difficulty is complicated by the lack of real understanding as to the exact nature of the Federal discount rate selected by the Water Resources Council.

In general the determination of interest rates[2] should consist of three factors: (1) the risk-free, inflation-free interest rate; (2) the risk premium associated with each entity as an on-going concern (i.e. business and financial risk); and (3) any additional risk premium associated with the construction of a given project (a function of the covariance of the risk between the project and the firm's existing portfolio of projects). It is worth noting that while (1) would be the same for both the government and the private corporation, (2) would be larger for the private corporation, while (3) might be greater for the government depending on the covariance.[3]

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[1]Charles W. Howe, Benefit-Cost Analysis for Water System Planning, Water Resource Monograph Series, no. 2 (Washington, D.C.: American Geophysical Union, 1971), pp. 80-81.

[2]This discussion of the interest rate will be on a very general level. For a thorough discussion of the choice of a discount rate for analysis see:

a. Otto Eckstein. Water Resource Development - The Economics of Project Evaluation. (Cambridge: Harvard University Press, 1958) Chapter IV "The Benefit-Cost Criterion, continued" pgs 81-109.

b. Subcommittee on Evaluation Standards. "Proposed Practices for Economic Analysis of River Basin Projects" pgs. 22-24.

[3]According to Eckstein. " The most important risks of the power program as a whole are that the technology will make the plants obsolete, that economic development will slow down or will take a turn which will not require as much power as anticipated, and finally that serious depressions may reduce the demand" pg. 82.

For the privately financed alternative it can be presumed that the measure of the opportunity cost is similar to the return on the firm's financial instruments. It is generally accepted that the market rates of interest of various securities contain inflationary premiums. By computing the cost of obtaining funds, subtracting the premium associated with inflation, and adding in any additional risk premium associated with the construction of a given project, the appropriate discount rate for this analysis could be determined.

For the government discount rate the process is not as simple. The factors which determine the government rate are not easily verifiable, but the existing rate is either: (1) the rate associated with the government securities in the marketplace, (2) the opportunity cost of capital to government, or (3) the social rate of time preference. The first of these is self evident and easily measureable. The opportunity cost "can only be estimated by tracing the capital to its source and by discovering its value in the use to which it would be put in the absence of the public project. Since the money is actually raised by taxation, the incidence of the marginal taxes necessitated by a project must be assigned to various businesses and households. Specific increases (or forestalled reductions) of taxes must be assumed and assumptions about the incidence of these taxes must be made. Once the tax money is traced to its source, its value in the alternative use can be estimated."[1]

The social rate of time preference is based upon "social policy, as derived from the political process, [which] may prefer [the] rejection of present intertemporal preferences in favor of a redistribution of income towards future generations. . . . It is not logically inconsistent for the same person to be willing to borrow at high interest rates to increase his present consumption while voting to spend tax money to build a project from which future generations will benefit, for in the case of a vote to tax, he can be sure that the other individuals in the society will be compelled to act similarly. Also, the distribution of voting power differs from the distribution of economic power in the market."[2]

The difficulty in determining the inflation free rate, as was discussed in the case of the privately financed alternative, thus becomes much more complex in the case of the Federally financed tidal plant. A cursory analysis by a contractor to NED calculated inflation free discount rates of 11% to 12% for a representative the private utility and 3% to 5% for the Federal Government, the latter being based upon the opportunity cost of capital. These rates are very preliminary and are presented for informational purposes only.

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[1]Eckstein, Otto. Water Resource Development - The Economics of Project Evaluation. pg 97.

[2]IBID. pgs 99-100.

The above discussion of discount rates presented some of the theoretical questions involved in this analysis. However, current policy directives are specific.

The "Principles and Standards" of the Water Resources Council mandates

> "The discount rate will be established in accordance with the concept that the Government's investment decisions are related to the cost of Federal borrowing"

and it is currently set at 6-7/8%. There is no alteration of this rate permitted. This may result in a limited change in the impact of relative price increases upon benefit to cost analysis since benefits and costs will most likely be discounted at rates different from those that would be theoretically valid.

b. Price Shifts

Relative price shift analysis is utilized in order to fully quantify the benefits resulting from power generation with a renewable resource. The price for any good can change relative to the general level of prices. Potential shifts, both negative and positive, can occur in the following project related areas: fossil fuel costs; cost of building the tidal project and the alternative plant; operation and maintenance (O&M) costs; cost of transmission lines and substations, and land costs. Although any price can shift, the direction and amount of any price shift can rarely be determined. Each of the items mentioned above is discussed below, however the base case analysis will focus upon the relative price shifts of the fossil fuel input to the thermal alternative - oil. Other relative price shifts will be examined as a sensitivity analysis.

(1) Fossil Fuels. The fuel costs for the alternative to the proposed tidal project will probably continue to rise more rapidly than the rate of general inflation. This parameter, an important difference between the proposed project and its alternative, is difficult to project due the myriad of variables which need to be considered, ranging from the development of new technologies to the political climate among the Organization of Petroleum Exporting Countries (OPEC).

Long run increases in the relative price of fossil fuels would tend to be dampened by three major factors. One, as the relative prices of existing forms of fossil fuels increase, prices would be reached at which existing technologies - e.g. shale oil recovery, would become economically feasible. In a market economy a substitution effect would occur given that the cross-elasticity of demand is high in the long run for the production of electricity from alternative energy sources and therefore the demand for existing fossil fuels as energy inputs would be transferred to other forms of energy. With demand reduced, given a competitive market economy (this would be approached given a long enough time period), price increases would slow. Two, over time, new technologies for energy production - i.e. fusion power, would become available. These forms of energy, when available, would then become economically feasible at a certain price and would also dampen further price rises among fossil fuels. Three, as the price of energy production rises relative to other goods, the rate of growth in the demand for all energy forms would be reduced below that which would otherwise be experienced. This factor although larger in the long run would remain small overall due to the low price elasticity of demand for energy. The combination of these factors would alleviate some of the upward pressure on prices.

Due to the uncertainties involved in energy price projection and forecasting of the development of alternative energy sources, relative price shifts for fossil fuels are be limited to one lifetime of the thermal alternative - to the year 2023. It is assumed that by this time price increases will be mitigated by technologic developments. Price projections are broken into two time periods: (1) escalation from the present to 1994, when the project comes on line; and (2) from 1994 to 2023, over the first life of the alternative. In addition three rates are utilized for sensitivity reasons - a low rate, a middle and most likely rate, and a high rate.

NED did not perform an in-depth analysis of potential price increases in the rate of fossil fuel at this stage of analysis due to the large number of published studies already available. The studies which were employed for this analysis include: figures generated utilizing the Department of Energy's P.I.E.S. model; a small contract to Meta Systems for a literature search; the Reassessment of Fundy Tidal Power - Reports of the Bay of Fundy Tidal Power Review Board and Managment Committee, November 1977; and a study performed for the Electric Power Research Institute. These studies are not documented in detail but rather their basic results are presented with the reader referenced to the background document for further details.

Historical background to the increase in oil prices recently experienced is given in the Reassessment of Fundy Tidal Power. pgs. 241-243.

"The world oil market has been subject to major changes in recent years. During the 1960's world production of crude petroleum more than doubled at declining real prices. In 1971, for example, the wellhead price of crude oil in the U.S.A. was slightly below the wellhead price in 1961, measured in constant dollar values (actual price adjusted for the wholesale price index for industrial commodities). The real market price of crude oil exported by members of the Oil Producing and Exporting Countries (OPEC) declined by nearly 25 per cent over the same period (actual price in dollars adjusted for the price of exports from industrialized countries).

The aggressive market intervention by OPEC in the early 1970's resulted in a tremendous increase in the price of internationally-traded oil. Over the period 1971 to 1974, the job market price of oil exported from OPEC countries increased by 475 per cent in current prices and by more than 300 per cent in prices adjusted for the price of exports from industrialized countries. Prices of crude oil from other sources followed the export prices from OPEC countries with various time lags and by varying, but substantial, rates of increase.

This sudden increase in the price of crude oil, generally considered as the reference price for all energy commodities, reverberated throughout the energy sector. The effects on production and consumption patterns are still not very clear, primarily because it is impossible to separate the effects resulting from this price increase from effects of the serious economic recession experienced by the leading industrial countries in recent years.

The intermediate and long-term outlook with respect to crude oil prices is clouded by uncertainty and is the subject of much speculation. The proven reserves of crude oil as of January 1, 1976 were about 660 billion barrels, of which more than half was located in the Middle East. These reserves are sufficient to cover 34 years of consumption at the level of 1976, but would provide for only 19 years if consumption were to increase annually by 6.2 per cent as it did over the period 1965-1975. However, additional oil reserves will be discovered and the higher prices that now prevail will encourage additional recovery from known reservoirs."

(a) The Department of Energy utilizing the P.I.E.'s model has made some fossil fuel price projections over a short time horizon. DOE projections from 1976 to 1990 are that annual real rates of price increase of 0% and 5% are equally likely. These projections demonstrate the type of impact that an increase in the price of an energy input can have on the demand for that input. Table 3, of the "Executive Data Summary" of DOE's PIES Model Report, entitled United States Total Gross Supply/Consumption of Energy Resources - BTU Growth Rates from 1975 (with natural gas regulation), projects the following annual BTU growth rates for the consumption of oil:

Increase In the Price of Imported Oil (Percent)	Year	Annual BTU Growth Rate (Quadrillions)
Zero (Series C)	1985	3.06
	1990	2.72
Five (Series F)	1985	2.71
	1990	1.98

As the time horizon lengthens and the price increases at a faster rate, demand growth, in this case, is significantly muted.

(b) Meta Systems extracted the sets of projections from cited literature detailed in Table 2.

(c) The Bay of Fundy Tidal Power Review Board and Management Committee concluded:

"Weighing the considerations summarized in the preceding discussion, the following projections were adopted for the purpose of this study.

- Until 1990, the assumed first year of operation of a tidal power project, international crude oil prices, in constant dollars, will remain close to the level of 1975. In other words, it is assumed that producers will be able to adjust prices to "world inflation", as determined by the average price level of products exported from the industrialized countries and obtain an average price in constant dollar values comparable to the price obtained by the main exporting countries in 1975. Actual prices are likely to fluctuate considerably around this average. It is further assumed that the Canadian price will be the same as the world market price. However, even if the Canadian price were kept at a different level, it is appropriate to evaluate alternative modes of generation at world market prices.

Beyond 1990, relative oil prices are assumed to increase by, on the average, 1 per cent per year. For the purpose of sensitivity analysis two alternative assumptions were made. The low price alternative assumes no increase over the planning period and the high price alternative assumes a 2 per cent average annual increase through the planning period."

TABLE 2. PROJECTION OF REAL CRUDE OIL PRICES ($/BARREL) AND RATES OF INCREASE[1]

Year	DRI	M.I.T.	EPRI	Pindyck	
1977	11.87	12.00		10.70	
78	↓		12.70	10.28	
79	(2.7%/yr)			10.19	
80	↓			10.26	
81	13.18	↓	↓	↓	
82	↓			↓	
83	(3.6%/yr)	(5.5%/yr)	(5.5%/yr)	(1.9%/yr)	
84	↓			↓	
85	15.18			11.28	
86	↓			↓	
87	(3/6%/yr)			(2.1%/yr)	
88	↓	↓	↓	↓	
89				↓	
90	18.16	24.00	23.00-25.00	12.51	↓
95	?	"	"	13.80	↓
2000		"	"	15.18	(2.5%/yr)
2005		"	"	16.72	↓
2010				20.52	↓
2010-25		"	"		
		"			

[1]Data Resources, Inc., "U.S. Long Term Review, Winter 1978," and "Chemical Review".

M.I.T. Workshop on Alternative Energy Strategies, "Energy: Global Prospects 1985-2000," New York, 1977.

Electric Power Research Institute, "Outlook for World Oil Into the 21st Century," New York, May 1978.

Robert S. Pindyck, "Gains to Producers from the Cartelization of Exhaustible Resources," Review of Economics and Statistics, Harvard University, May 1978.

Table 3 details their projections for New England.

TABLE 3

PROJECTED FUEL COSTS
NEW ENGLAND
(June 1976 dollars)

AVERAGE ASSUMPTIONS

	1985	1990	1991-2010*
Residual Oil (0.3% Sulphur)			
$/Million Btu	2.53	2.54	1% annual escalation
$/Blb.	15.00	15.85	1% annual escalation
Distillate Oil			
$/Million Btu	2.89	2.90	1% annual escalation
$/Bbl.	17.00	17.10	1% annaul escalation

*Annual escalation rates are over and above any average inflationary increases as reflected in the Consumer Price Index (CPI)

(d) Foster Associates under contract to the Electric Power Research Institute came to the following conclusions:

"Combining the influences indicated above, foreign oil prices are projected in terms of the generally accepted marker crude, Saudi Arabian light, FOB[1] Saudi Arabia, as set out in Table [4] (in constant 1975 dollars per barrel).

TABLE 4

WORLD CRUDE OIL PRICE PROJECTION

	Base Case	Low Case	High Case	Range of Uncertainty
1976	$11.10	$11.10	$11.10	--
1985	10.00	4.00	15.00	375%
1990	11.00	6.00	17.00	283%
2000	16.75	11.00	22.00	200%

[1]FOB is a shipping term - free on board - basically meaning the cost of product at the source exclusive of freight.

The base case corresponds to about a 10 percent price drop between 1976 and 1985, about a 2 percent per year growth between 1985 and 1990, about 3-1/2 percent per year growth between 1990 and 1995, and about 5 percent growth from 1995 to 2000. . .

The low case in 1985 represents a near total collapse of cartel pricing by OPEC. Even so, the low case price in 1985 would still be well above cost because enough countries like Saudi Arabia, Kuwait and Libya who do not need the current income would unilaterally cut production sharply rather than sell at prices that were much lower than current levels. After 1985, the low case reflects the consequence of new reserves (and/or alternates) being at a much lower cost than anticipated.

The high case price in 1985 reflects what might happen if OPEC ignored the restraints on price previously discussed. The high case prices after 1985 could occur if new reserves (and/or alternates) are at a much higher cost than anticipated. A sustained very high real price of oil such as shown in the high case is quite unlikely, for example, because such a high price in 1985 likely would bring out enough new energy supply, cut demand enough, and/or trigger enough other counter-measures by consumers to bring price down again. . .

The above forecast, of course, assumes that essentially a single price structure will continue in the foreign area in each of the three cases."[1]

The range of the uncertainty given in the previous table is informative in considering the level of confidence associated with any given projection.

Based upon the above studies the following annual rates of real oil price escalation are estimated for the purposes of this study.

	1978-1994	1994-2023
Low Rate	1%	1%
Medium Rate	3%	1%
High Rate	5%	1%

The initial fuel cost for the alternative, as provided by FERC, is $2.80/million BTU. Utilizing a conversion rate of 5,900,000 BTU/ Barrel this would be a cost of $16.52 per barrel.

[1]Electric Power Research Institute. Fuel and Energy Price Forecasts. Prepared by Foster Associates, Inc. EPRI EA-411 Final Report Volume II. March 1977. pgs III 9-11.

(2) Costs of Building the Tidal Project and the Alternative Plant

a. Construction Costs

Two sources of information were relied upon in analyzing this facet of the relative price shift analysis: a preliminary analysis performed by Meta Systems and the Reports of the Bay of Fundy Tidal Power Review Board and Management Committee.

Historically both construction costs and wages have risen at a rate faster than that of general inflation as documented in Table 5. The relative rise in construction costs was largely due to a sharp rise in construction labor costs that exceeded the rise in general labor costs in the late 1960's and early 1970's.[1] Recently construction labor costs have increased more slowly than general labor costs. The measure of the general level of prices employed was the consumer price index published by of the Department of Commerce.

Construction materials have increased sharply in price over the last 10 years. This increase, however, has not been out of line with industrial commodities as a whole. Industrial commodities have, nevertheless, increased at a slightly faster rate than consumer prices.

Deflated construction costs have exhibited the following real rates of change:

0.9 percent for 1950-1970
1.8 percent for 1970-1978

Construction labor cost increases which rose sharply in the late 1960's and early 1970's and were largely responsible for the relative rise of construction costs during that time period are not expected to experience a relative rise during the period through project completion. "The cost of labor ..... is a major element in the cost of construction ..... It is expected that the net result of various factors [productivity increases, fringe benefit increases, etc.] will be that real construction wage costs will not significantly change in the Maritime provinces during the 1980's."[2] This conclusion by Bay of Fundy Tidal Review Board and Managment Committee can be assumed to be valid for the area of the proposed Cobscook Bay Tidal Power Project.

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[1]Meta Systems Inc.

[2]Reassessment of Bay of Fundy Power. pgs. 239-241.

TABLE 5

Deflated Costs

Year	Construction Costs*	Construction Wages	General Wages	Indust. Commod. Prices	Electical Machinery & Equipment	Consumer Prices
50	62.1	1.86	1.44	78.0	68.9	72.1
51	67.7	2.02	1.56	86.1	78.9	77.8
52	69.4	2.13	1.65	84.1	77.8	79.5
53	71.0	2.28	1.74	84.8	80.0	80.1
54	71.0	2.39	1.78	85.0	81.6	80.5
55	72.6	2.45	1.86	86.9	82.9	80.2
56	72.6	2.57	1.95	90.8	89.5	81.4
57	79.8	2.71	2.05	93.3	96.4	84.3
58	80.6	2.82	2.11	93.6	98.4	86.63
59	82.3	2.93	2.19	95.3	99.9	87.3
60	83.1	3.08	2.26	95.3	99.5	88.7
61	83.9	3.20	2.32	94.8	98.2	89.6
62	86.3	3.31	2.39	94.8	96.7	90.6
63	87.9	3.41	2.46	94.7	95.7	91.7
64	90.3	3.55	2.53	95.2	95.1	92.9
65	92.7	3.70	2.61	96.4	95.1	94.5
66	96.0	3.89	2.72	98.5	97.2	97.2
67	100.0	4.11	2.83	100.0	100.0	100.0
68	105.6	4.41	3.01	102.5	101.3	104.2
69	112.5	4.79	3.19	106.0	102.9	109.8
70	120.1	5.24	3.36	110.0	106.4	116.3
71	127.9	5.69	3.57	114.0	109.5	121.3
72	134.9	6.03	3.81	117.9	110.4	125.3
73	147.7	6.37	4.08	125.9	112.4	133.1
74	173.0	6.75	4.41	153.8	125.0	147.7
75	186.4	7.25	4.81	171.5	140.7	161.2
76	193.6	7.70	5.22	182.4	146.7	170.5
77	211.3	8.09	5.67	195.1	154.1	181.5
78	231.	8.60	6.15	210.	164.	194.5

*"A number of cost indices are available, including the American Appraisal Company indices, the Boeckh indices, the Engineering News Record indices, and the EPA indices. We chose to use the Department of Commerce Composite index because it provides an overall index which accounts for productivity changes." Meta Systems Inc.

On the basis of this analysis it is assumed that construction costs will continue to escalate at a rate greater than that of general inflation. This rate will be closer to the long run real increase due to the mitigation in real increases of wages and the lower rate of increase in the cost of energy inputs. Therefore a rate of real price increase of 1.1 percent per year is assumed for the construction cost.

(b) Cost of Electrical Machinery and Equipment

To the extent that the cost of building these plants consists of electrical machinery and equipment, the escalation rate in relative costs may be lower than 1.1 percent. Real electrical machinery and equipment prices grew at the following rates:

-0.2 percent per year for 1950-1970
-1.0 percent per year for 1970-1978

The future trend is assumed to approximate the long run trend. For the purpose of this report a rate of -.25 percent per year is utilized.

(c) To determine escalation rates for the building cost of the project and of the alternative, weights are applied to the escalation rates for the construction cost and electrical machinery and equipment cost and the resulting two terms summed. These weights are defined as the fraction of total unescalated cost that is attributeable to each of these cost categories.

Meta Systems calculated an escalation rate of approximately 1.1% per year for the tidal plant, assuming very little of the cost of the tidal plant consisted of electrical equipment; and a rate of approximately .85% per year for the combined cycle alternative with weighting based upon several telephone conversations with local utilities.

Based upon a cursory analysis by the Corps of the tidal project's cost, it was decided that a large amount of its construction cost was in electrical equipment - approximately 32%. Utilizing this weight the expected escalation rate is estimated to be .67% per year.[1] Further telephone calls regarding the composition of the combined cycle plant yielded a weight for electrical equipment of approximately 43%. With this weight the escalation rate for the alternative would be .52% per year.

Sensitivity tests utilizing price escalation factors for the replacement plant for the alternative, scheduled for thirty years after the initial construction, will not be made due to the potential substitution of energy sources and the difficulty of price projection that far in the future.

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[1] (1.1%)(.68) + (-.25%)(32) = .67%

Therefore, sensitivity tests will be run for this category for both Meta's estimates and the Corps' estimates.

(3) Operation and maintenance costs are assumed to grow in accordance with manufacturing wages, electrical equipment and machinery prices, and industrial commodity prices. Manufacturing wages have grown at a rate of 5.3 percent per year from 1950 to 1978. Relative to the consumer index, they have grown at a rate of about 1.6 percent per year. The rate of relative growth was

1.9 percent per year for 1950-1970
1.1 percent per year for 1970-1978

Weighting the equipment and industrial commodities indices equally, their rate of relative growth was -0.2 percent per year from 1950 to 1978 and

-0.5 percent per year for 1950-1970
0.4 percent per year for 1970-1978

Assuming that the relative rate of growth of these costs will be 0.0 percent and that relative labor costs will grow at 1.2 percent to 1.4 percent per year; then relative O&M costs will grow about 0.5 percent to 0.8 percent per year.

Furthermore, assuming increases in productivity will occur similar to other industries, then O & M costs will probably not grow relative to the general price level. In fact, they may decline. Thus the estimate for O & M costs is a rate of increase between -0.5 percent and 0.0 percent per year. For this study a rate of -0.25 percent per year is used for sensitivity analysis.

(4) Cost of Transmission Lines and Substations.

In line with the discussion of item 2 above the rate of real price escalation for transmission lines and substations is expected to be lower than 1.1 percent per year. For this analysis a rate of .43 percent per year is utilized for sensitivity analysis based upon a 50% weighting of both construction costs and electrical equipment and machinery.

(5) Land Costs. Since land is fixed in quantity, it should rise in value faster than general inflation, and historically this has been the case. However, increases in land value are not uniform; large rates of increase are experienced in metropolitan areas or highly productive agricultural areas, with smaller rates of increase in other areas. Land values can therefore not be projected with a great degree of credibility. This uncertainty of projection, in

addition to the relatively small proportion of land costs to total construction costs, serves as the basis for excluding land values from the analysis.

Consideration was given to tracing the impact of a relative increase in fuel prices upon construction costs, maintenance materials, interim major replacements and other project and alternative related input; using input-output coefficients. This would provide for a complete consideration of the impact of escalating fuel prices upon the project's economics. This was rejected, however, for the following reasons: (1) it is difficult to determine whether the same ratio of factor inputs to total inputs will exist throughout the economy over time; (2) there is lack of knowledge concerning product substitution possibilities; and (3) there is a lack of authoritative projections for such alternative products.

On the basis of the above discussion, the following analysis will focus on the increase in the relative prices of the fossil fuel input to the thermal alternatives power production cost. Several sensitivity tests will be run analyzing different rates of price escalation factors for various project cost and benefit categories.

Power Value of Tidal Power

The methodology utilized to develop power values for tidal power is based upon the Federal Power Commission's manual Hydroelectric Power Evaluation FPC P-35. This methodology has been incorporated into a "life cycle costing" model by the Federal Energy Regulatory Commission (FERC, formerly FPC) and will be detailed in their forthcoming revised Hydroelectric Power Evaluation. The computation of power values is the same for both hydroelectric and tidal power. The following is taken from the final draft of the above. Specifically, Chapter 5 entitled "Computer Model for Determining Power Value of Hydroelectric Power".

"The annual value of hydroelectric power consists of (1) a capacity value, which is developed from the fixed elements of the cost of power supply from an alternative electric generating plant; and (2) an energy value, which is developed from the variable elements of the cost of power supply from the alternative plant. Within these two basic components there are the following four types of costs that enter into the power value determination:

a. Costs of electric power delivered to the bus bar. (The bus bar is the transfer point between the generating station and the sending substation.) These include generating facility investment costs and the operating and maintenance expenses required to produce power.

b. Investment and operating costs, including the value of energy losses, of sending substation facilities needed to transform bus bar voltage to transmission voltage.

c. Investment and operating costs, including the value of line losses, of transmission required to transmit the electric power to market.

d. Costs of the at-market substation facilities required to convert the energy from transmission system voltage to that most appropriate for delivery to the market. These include facility investment costs, operating costs and substation losses.

A computer program has been developed for assimilating these costs and calculating the capacity and energy value of proposed hydroelectric projects. In this model, investment and operating costs are used to develop annual capacity and energy values at various points for any given number of years up to 100 years. The model also permits the use of time varying cost factors and the application of present worth arithmetic, thereby providing for basic life cycle cost analysis or variable sensitivity analyses over the life of a hydroelectric project.

In studies involving life cycle analysis the program varies those variable cost elements based on an annual fixed rate of escalation,[1] then through the application of present worth and capital recovery factor formula determines the annual levelized costs of these elements. The program, in general, is in an initial phase of development. Future modification is expected to include at least the introduction of supplementary production costing programs to refine energy value evaluation, and additional inputs to refine the life cycle analysis capability."

Table A-1 displays general input parameters. (Tables prefixed by A are located in the Appendix) Tables A-2 and A-3 display sample tidal and thermal input data, respectively, utilized in the program operation.

Escalation rates enter into the computer model via the generalized term

$$\text{PRICE} = \text{initial cost} \times (1 + \text{annual escalation rate})^{n}$$

$$\text{PRICE} = \text{Escalated fuel cost}$$

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[1]This was modified for this study to permit the input of a rates each year during the 100 year economic evaluation period.

This will update the costs associated with the fuel input of the alternative, while the initial fuel cost data to be input into the program will be updated to 1994 relative price levels by hand. Thus, the computation of the power value of the tidal power plant at low tension connection at market will incorporate all the escalation factors. This point of the computer printout is utilized to maintain comparability with FERC power values. For sensitivity analyses the cost side-plant construction costs, operation and maintenance costs, and transmission and substation costs will be escalated by hand over the relevant period and capitalized to determine an escalated annual cost. On the benefit side, those costs of the alternative impacted will be escalated by hand and then input into the program.

Analysis.

As discussed in the methodology section of this report, this analysis is based upon relative price shifts of oil. In addition, two sensitivity analyses are performed: (1) relative price shifts among other factors - project construction costs, alternative construction costs, transmission line and related structure costs, and operation and maintenance costs; are examined; and (2) relative price increases of oil over the period 1994-2023 of greater than 1% are examined to see at what level a benefit to cost ratio greater than unity would be obtained.

a. Base Case

This case analyzes the impact of relative price shifts of fuel upon project economics. The following rates are utilized:

	1978-1994	1994-2023
Low Rate	1%	1%
Medium Rate	3%	1%
High Rate	5%	1%

Tables 6-8 detail the results of this analysis.

TABLE 6
Power Values[1] - 40% Plant Factor
(mills/kwh)

Fuel Escalation Rate	
1%	35.4
3%	45.7
5%	59.3

TABLE 7
Representative Benefit to Cost Ratios[2]

	Fuel Escalation Rates		
Project	1%	3%	5%
160 Dudley	.52	.67	.87
135 Cable	.56	.72	.93
140 Cooper	.56	.73	.94
110 Birch	.56	.72	.93
135 Goose	.56	.72	.94

A third statistic which is of relevance in relative price shift analysis is the break-even year. This is the year after project construction that the escalating power value equals or exceeds the cost of power generation from the tidal alternative. After this point the project begins to pay for itself.

TABLE 8
Number of Years to Break-Even Point

	Break-Even Value (mills/kwh)	Fuel Escalation Rates		
Project		1%	3%	5%
160 Dudley	68.0	-	-	26
135 Cable	63.7	-	-	19
140 Cooper	63.1	-	-	18
110 Birch	63.6	-	-	19
135 Goose	63.2	-	-	18

[1]The power value FERC calculated for a 125 MW tidal project with a plant factor of .31 was 31 mills/kwh. Their calculations do not consider price shifts. To ensure the consistency of benefit to cost comparisons, the computer model was calibrated utilizing a fuel escalation rate of 0%. In this case the computer calculated a power value of 30.64 mills/kwh. The basic values are in close agreement and therefore comparisons between standard benefit to cost ratios and those calculated herein can be made with relative confidence.

[2]These projects have the best standard benefit to cost ratios.

These tables indicate that while at the high fuel escalation rate the project's power cost will be lower than the alternatives at some point in the future, over the 100 year period beginning in 1994 the initial higher cost of the project's power is not compensated for by future, more heavily discounted, savings.

b. Sensitivity Analyses

The sensitivity analyses utilize the 140 MW Cooper project since it showed one of the highest benefit to cost ratios under both the standard and the relative price shift methods. The following alternative assumptions are made for each facet of cost studied with the resulting benefit to cost ratios presented in Table 9.

Annual Escalation Rate-Plant

	Corps	Meta
Tidal Plant	.67%	1.1%
Alternative Plant	.52%	.85%

Annual Escalation Rate-Operation and Maintenance

-.25%

Annual Escalation Rate- Transmission Line and Associated Costs

.43%

TABLE 9
Benefit to Cost Ratios
Sensitivity Analyses - 140 MW Cooper
Fuel Escalation Rate - 3%

	O + M 0%		O + M -.25%	
Transmission Line and associated Cost	0%	.43%	0%	.43%
Plant				
0%	.73	.72	.72	.72
Corps	.68	.67	.68	.67
Meta	.63	.63	.63	.63

The limited sensitivity exhibited under the scenarios - excepting plant cost, should not be surprising and should be interpreted with exceeding caution. The sensitivity evident is a result of the methodology for computing benefits and cost. Changes in plant cost, transmission line and associated structure costs, and fixed portion of operation and maintenance costs would impact the power value of tidal generation on the capacity side of the benefit ledger. But, since the tidal project analyzed does not have a dependable capacity credit presently, benefits do not rise. Thus for an escalation rate applied to fixed charges the cost of the tidal plant would rise, but the cost of the thermal alternative while rising would not be reflected in project economics.

In addition, the limited impact can be traced to the very low rates of escalation applied over short time periods. - i.e. $a(1 + .005)^{15} = 1.08a$, an increase of .5% for 15 years adds only 8% to the cost of the project facet.

An additional sensitivity analysis utilizes the following future relative price escalation rate for oil to determine a rate at which the project benefit to cost ratio would exceed unity.

Annual Escalation Rate 1994-2023
2%
3%

TABLE 10
Benefit to Cost Ratios
Sensitivity Analyses - 140 MW Cooper
Alternate Future Fuel Escalation Rates

	Fuel Escalation Rate 1979-1994		
Fuel Escalation Rate 1994-2023	1%	3%	5%
1%	.56	.73	.94
2%	.62	.80	1.04
3%	.68	.89	1.16

The following tables display the percentage increase in real terms of the price of oil over the time period 1979-2023 under the various cases examined and the actual price used as an input to the analysis.

TABLE 11

Percentage Increase in Real Oil Prices

	Fuel Escalation Rate		
	1%	3%	5%
To 1994	16.1	55.8	107.9
To 2023			
1%	56.5	110.0	180.2
2%	110.3	182.2	276.5
3%	181.8	278.1	404.6

TABLE 12

Increase in Real Oil Prices ($/Barrel)

	Fuel Escalation Rate[1]		
	1%	3%	5%
To 1994	19.18	25.74	34.35
To 2023			
1%	25.85	34.69	46.29
2%	34.74	46.62	62.20
3%	46.55	62.46	83.36

[1]Base cost $16.52.

While the 5%-2% and 5%-3% cases examined in Table 10 are presumed to be extremely unlikely, given the uncertainty associated with the energy sector it is a possibility.

D. Conclusion

The utilization of relative price shift analysis brings out the economic energy benefit associated with tidal power much more clearly. This dynamic economic approach results in the various tidal power project's benefit-to-cost ratios being enhanced. However, with this methodology and assuming relative price shifts for oil along expected levels, tidal power, while eventually providing net benefits during several years in the high escalation rate case, does not provide net benefits over the life of the project. The reasons for this include those which have always weighed against the tidal power concept - i.e. high initial cost and lack of dependable capacity; and the more recent infusion of funds into alternative, and in many cases, less expensive forms of energy. Thus, tidal power, though more competitive today, is still not justified, utilizing the assumptions made herein, on the basis of economic analysis as applied in accordance with the Water Resource Council's Principles and Standards.

TABLE A-1
GENERAL INPUT PARAMETERS

ESCALATION RATE;O&M-(PU)	0.0000
ESCALATION RATE;GENERATING PLANT-(PU)	0.0000
ESCALATION RATE;SUBSTATION-(PU)	0.0000
ESCALATION RATE;TRANSMISSION LINES-(PU)	0.0000
DISCOUNT RATE;STEAM PLANT-(PU)	.10500
DISCOUNT RATE;HYDRO PLANT-(PU)	.06875
FEDERAL INCOME TX RTE FOR CORP-(PU)	0.000
INVESTMENT TAX CREDIT-(PU)	0.000
BOND INTEREST RATE,THERMAL ALT-(PU)	0.000
BOND DEBT RATIO,THERMAL ALT-(PU)	0.000
BOND INTEREST RATE,HYDRO-(PU)	0.000
BOND DEBT RATIO,HYDRO(PU)	0.000

Table A-2

***** TIDAL POWER INPUT DATA *****

1-SERVICE LIFE OF PLANT-YEARS	100.
2-INITIAL PLANT OPERATION DATE	1987.
3-FINAL PLANT RETIREMENT DATE	2087.
4-ECONOMIC AMORTIZATION PERIOD-YEARS	100.
5-FRACTION OF CAPACITY DEPENDABLE-(PU)	1.00
6-PLANT CAPACITY-KW	125000.
7-INITIAL PLANT FACTOR-(PU)	.40
8-FINAL PLANT FACTOR-(PU)	.40
9-SENDING SUBSTATION OUTPUT VOLTAGE-KV	115.
10-SENDING SUBSTATION CAPACITY LOSS-(%)	.00
11-TRANSMISSION MILEAGE-MILES	123.
12-TRANSMISSION CAPACITY LOSS-(%)	5.00
13-RECEIVING SUBSTATION OUTPUT VOLTAGE-KV	115.
14-RECEIVING SUB. CAPACITY LOSS-(%)	0.00
15-HYDRO ADJUSTMENT FACTOR;CAPACITY-(PU)	0.0000
16-COST OF MONEY-(PU)	.06875
17-INSURANCE RATE;SUBSTATION-(PU)	0.0000
18-FEDERAL TAX RATE-(PU)	0.0000
19-MISCELLANEOUS TAX RATE-(PU)	0.0000
20-LOCAL AND STATE TAX RATE-(PU)	0.0000
21-REPLACEMENT RATE;SUBSTATION-(PU)	.0360
22-REPLACEMENT RATE;TRANSMISSION FACILITIES-(PU)	.0330
23-INSURANCE RATE;TRANSMISSION FACILITIES-(PU)	0.0000
24-TYPE OF TRANSMISSION OH=1 UG=2	1.
25-FACTOR FOR ADM.,GEN.,SUP. AND TRAN.-(PU)	0.00
26-TYPE OF FINANCING PRIVATE=1 PUBLIC=2	2.
27-INITIAL LOAD FACTOR-(PU)	.40
28-FINAL LOAD FACTOR-(PU)	.40
29-SEND. SUB. ANN. O&M COST-$/KW	.32
30-TRANSMISSION LINE ANN. O&M COST-$/KW	1.96
31-REC. SUB. ANN. O&M COST-$/KW	0.00
32-ESTIMATE OF SEND. SUB. INVST.-(DOLLARS)	2000000.
33-ESTIMATE OF REC. SUB. INVST.-(DOLLARS)	0.
34-ESTIMATE OF TRAN. LINE INVST.-(DOLLARS)	4000000.

Table A-3

***** COMBINED-CYCLE INPUT DAT *****
A

1-SERVICE LIFE OF PLANT-YEARS	30.
2-INITIAL PLANT OPERATION DATE	1987.
3-FINAL PLANT RETIREMENT DATE	2017.
4-AMORTIZATION PERIOD;SUB.&OH TRAN.(WD. POLES)-YEARS	30.
5-AMORTIZATION PERIOD;OH TRAN.(STEEL TOWERS)&UG-TRAN.-YEARS	30.
6-PLANT CAPACITY-KW	600000.
7-INITIAL PLANT NET HEAT RATE-BTU/KWH	9000.
8-FINAL PLANT NET HEAT RATE-BTU/KWH	9000.
9-FUEL TYPE COAL=1 OIL=2 GAS=3 NUCLEAR=4	2.
10-INITIAL PLANT FACTOR-(PU)	.30
11-FINAL PLANT FACTOR-(PU)	.30
12-SENDING SUBSTATION OUTPUT VOLTAGE-KV	345.
13-SEND. SUB. CAPACITY LOSS-(%)	1.00
14-TRANSMISSION MILEAGE-MILES	30.
15-TRANSMISSION CAPACITY LOSS-(%)	2.00
16-RECEIVING SUBSTATION OUTPUT VOLTAGE-KV	345.
17-RECEIVING SUBSTATION CAPACITY LOSS-(%)	0.00
18-FIXED FUEL FACTOR-(PU)	0.00
19-RESERVE FUEL LEVEL-DAYS	90.
20-COST OF MONEY-(PU)	.10500
21-INSURANCE RATE;PLANT AND SUBSTATION-(PU)	.0025
22-FEDERAL TAX RATE-(PU)	.0206
23-MISCELLANEOUS TAX RATE-(PU)	0.0000
24-LOCAL AND STATE TAX RATE-(PU)	.0379
25-REPLACEMENT RATE;PLANT AND SUBSTATION-(PU)	.0035
26-REPLACEMENT RATE;TRANSMISSION FACILITIES-(PU)	.0035
27-INSURANCE RATE;TRANSMISSION FACILITIES-(PU)	.0025
28-FACTOR FOR ADM.&GEN.;SUBSTATION AND TRANSMISSION-(PU)	.32
29-ESTIMATE OF GENERATING PLANT INVESTMENT(DOLLARS)	195000000.
30-ESTIMATE OF SEND. SUBSTATION INVESTMENT(DOLLARS)	5735000.
31-ESTIMATE OF RECE. SUBSTATION INVESTMENT(DOLLARS)	0.
32-ESTIMATE OF TRANSMISSION LINE INVESTMENT(DOLLARS)	9464000.
33-INITIAL COST OF FUEL-DOLLARS PER MBTU	4.36
34-FIXED COST FRACTION FOR O&M-(PU)	.19
35-INITIAL SYSTEM DISPLACED ENERGY COST-MILLS/KWH	31.78
36-DUMMY************************************	0.00
37-ADVALOREM TAX RATIO-(PU)	.99
38-FACTOR FOR ADM.&GEN.;GENERATING PLANT-(PU)	.39
39-INITIAL SPECIFIC HEAT OF FUEL-BTU PER #,GAL.,OR CF	135000.
40-FINAL SPECIFIC HEAT OF FUEL-BTU PER #,GAL.,OR CF	135000.
41-INITIAL LOAD FACTOR-(PU)	.30
42-FINAL LOAD FACTOR-(PU)	.30
43-PLANT ANNUAL O&M COST-$/KW	18.12
44-SENDING SUBSTATION ANNUAL O&M COST-$/KW	.60
45-TRANSMISSION LINE ANNUAL O&M COST-$/KW	.05
46-RECEIVING SUBSTATION ANNUAL O&M COST-$/KW	0.00
47-TYPE OF TRANSMISSION OH=1 UG=2	1.
48-TYPE OF FINANCING PRIVATE=1 PUBLIC=2	1.
49-AVERAGE ANNUAL COST OF NUCLEAR FUEL INVENTORY-$/KW	0.00
50-ESTIMATED NUCLEAR FUEL BURN UP COSTS-MILLS/KWH	0.00

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